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RACT 2 Case-by-Case Evaluation
Installation Permit No. 0052-I020

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Pennsylvania Department of Environmental Protection
Bureau of Air Quality

RACT SIP COMPLETENESS CHECKLIST

TO BE FILLED IN BY REGIONAL STAFF AND SUBMITTED TO CENTRAL OFFICE

Facility Name: U.S. Steel Mon Valley Works – Clairton Plant

RACT Plan Approval/Permit Number: Installation Permit No. 0052-I020

Plan Approval/Permit Issuance Date: April 24, 2020

TECHNICAL MATERIALS

Included	Not Included	Not Applicable	
☒	☐	☐	**Identification of all regulated (NOx and VOC) pollutants affected by the RACT plan (Review memo and RACT Permit)**
☒	☐	☐	**Quantification of the changes in plan allowable emissions from the affected sources as a result of RACT implementation. (Review Memo)**
☐	☐	☒	**Rationale as to why applicable CTG or ACT regulation is not RACT for the facility. (Review Memo)**
☐	☐	☒	**Demonstration that the NAAQS, PSD increment, reasonable further progress demonstration, and visibility, as applicable, are protected if the plan is approved and implemented. (Review Memo)**
☐	☐	☒	**In the event of actual emission increase as a result of RACT SIP revision: Modeling information to support the proposed revision, including input data, output data, model used, ambient monitoring data used, meteorological data used, justification for use of offsite data (where used), modes of models used, assumptions, and other information relevant to the determination of adequacy of the modeling analysis. (Review Memo)**
☒	☐	☐	**Include evidence, where necessary that emission limitations are based on continuous emission reduction technology. (Review Memo)**
☒	☐	☐	**State in RACT PA/OP that expiration date shown in PA or OP is for state purposes. Either use the statement below or redact the expiration date on the permit.** **(Sample: The expiration date shown in this permit is for state purposes. For federal enforcement purposes the conditions of this operating permit which pertain to the implementation of RACT regulations shall remain in effect as part of the State Implementation Plan (SIP) until replaced pursuant to 40 CFR 51 and approved by the U.S. Environmental Protection Agency (EPA). The operating permit shall become enforceable by the U.S. EPA upon its approval of the above as a revision to the SIP.) (RACT Permit)**
☐	☐	☒	**Include evidence that the State has the necessary legal authority under State law to adopt and implement the RACT plan. (Reference of PA's Air Pollution Control Act (January 8, 1960, P.L. 2119, as amended and 25 PA Code Chapter 127 (NSR), and 25 PA Code Chapter 129 §§129.91 – 95 in RACT PA/OP). (Review memo or more likely operating permit)**

☒	☐	☐	**State that independent technical and economic justification for RACT determination by the Department was performed. As long as you reviewed the companies proposal you may agree with it but that must be stated. (Review memo)**
☐	☐	☒	**Confidential Business Information excluded, highlighted or marked. Please also redact all checks from the application. (Review Memo, RACT Permit, RACT Plan by the company)**
☒	☐	☐	**Adequate compliance demonstration, monitoring, recordkeeping, work practice standards, and reporting requirements. (Review memo and RACT Permit)**

ADMINISTRATIVE DOCUMENTS

Attached	Not Attached	Not Applicable	
☒	☐	☐	**Signed copy of final RACT Plan Approval/Operating Permit.**
☒	☐	☐	**Redacted copy of the RACT Plan Approval/Operating Permit. Reviewer should be able to read the redacted text. (We can do electronically if the PA/OP is uploaded in AIMS or available in pdf format). Make sure that the expiration date of the operating permit is redacted. SIPs do not expire.**
☒	☐	☐	**Signed Technical Support Document or Review Memorandum. The review memo should contain a discussion about previous case by case RACT determinations so that requirements can be compared**
☒	☐	☐	**Public Notice evidence: Include a copy of the actual published notice of the public hearing as it appeared in the local newspaper(s). The newspaper page must be included to show the date of publication. The notice must specifically identify by title and number each RACT regulation adopted or amended. A signed affidavit showing the dates of publication and the newspaper clipping is best. Next best is a copy of the newspaper clippings from all days the article was published. An email showing that the newspaper article was purchased is acceptable unless the EPA receives comments during their comment period stating that there is no proof of publication. The newspaper notice must say that the case by case requirements will be submitted to the EPA as an amendment to the SIP**
☒	☐	☐	**A separate formal certification duly signed indicating that public hearings were held. If no public hearings were held the review memo should state that.**
☒	☐	☐	**Public hearing minutes: This document must include certification that the hearing was held in accordance with the information in the public notice. It must also list the RACT regulations that were adopted, the date and place of the public hearing, and name and affiliation of each commenter. If there were no comments made during the notice period or at the hearing, please indicate that in the review memo.**
☒	☐	☐	**Comment and Response Document: A compilation of EPA, company, and public comments and Department's responses to these comments.**
☒	☐	☐	**Copy of RACT proposal, amendments, and other written correspondence between the Department and the facility.**

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1811

Reasonable Available Control Technology INSTALLATION PERMIT

Issued To:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855	**ACHD Permit#:**	**0052-I020**
		Date of Issuance:	April 24, 2020
		~~Expiration Date:~~	~~(See Section III.12)~~

Issued By: Digitally signed by JoAnn Truchan, PE Date: 2020.04.24 15:18:28 -04'00'

JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: Hafeez Ajenifuja Digitally signed by Hafeez Ajenifuja Date: 2020.04.24 15:11:04 -04'00'

Hafeez Ajenifuja
Air Quality Engineer

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

Pages 2 through 19 have been redacted.

A. Boilers No. 1 & 2:

Process Description: Steam Production
Facility ID: B001 & B002
Capacity: 760 MMBtu/hr; 481 MMBtu/hr
Raw Materials: Desulfurized coke oven gas and natural gas
Control Device: NA

1. Restrictions:

~~a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)~~

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. 1 shall not at any time exceed 0.48 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. Nitrogen Oxide (NO_X) emissions from each Boiler No. 2, shall not at any time exceed 0.37 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

d. The NOx emissions in conditions V.A.1.b and V.A.1.c above shall be determined by a thirty (30) day rolling average and a twelve (12) month rolling average Continuous Emission Monitoring (CEM) data for the lbs/MMBtu and tons/yr emission limitation respectively. (25 Pa Code §129.99; RACT Order No. 234, Condition 1.5; 2102.04.b.5; §2105.06.d)

e. NO_X emissions from each Boilers No. 1 or 2 shall not exceed the limitations in Table V-A-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-A-1: NO_X Emission Limitations

Process	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 1	0.48	364.80	1,598
Boiler 2	0.37	177.97	780

*A year is defined as any consecutive 12-month period.
**Based on a 30-day rolling average.

2. Testing Requirements:

a. Emissions of NO_X may be determined by the CEMs required in Condition V.A.3 below in lieu of a stack test to determine compliance with the emissions limitation of Conditions V.A.1.b, V.A.1.c and V.A.1.e above. (§2103.12.i; §2103.12.h.1; §2108.02; §2108.03; 25 Pa Code §129.100)

~~b. The Department reserves the right to require additional emissions testing sufficient to assure~~

~~compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 and §2108.02. (§2103.12.h.1)~~

3. Monitoring Requirements:

a. The permittee shall install, operate, and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with 25 PA Code §§139.101 - 139.111 relating to requirements for continuous in-stack monitoring for stationary sources. (§2108.03.b.2 and RACT Plan 234)

4. Record Keeping Requirements:

a. The permittee shall maintain all appropriate records to demonstrate compliance with the requirements of §2105.06. Such records shall provide sufficient data and calculations to clearly demonstrate that all requirements of §2105.06 are met. The permittee shall record and maintain such data and information required to determine compliance for the facility in a time frame consistent with the averaging period of the requirements of both §2105.06 and RACT Order No. 235. Such information shall include, but not be limited to, the following minimum information which shall be submitted to the Department as a written report at three month intervals: (§2102.04.b.5; §2108.03.d, §2105.06; 25 Pa Code §129.100; RACT Plan 234)

1. All recording and reporting required by Section 2108.03 of Article XXI and entitled "Continuous Emission Monitoring."
2. An identification of each instance during the reporting period during which emissions exceeded the applicable emission limitation rates in Condition V.A.1.b above and an identification of the reasons, if known, for such exceedance. The averaging period used for making such identification shall correspond to the averaging period specified in condition V.A.1.d above.
3. An identification of each period during which the continuous emission monitoring system was inoperative, except for zero and span drift checks, the reasons therefore, and the nature of repairs or adjustments performed or to be performed.
4. An identification of calibrations, zero and span drift checks, and other quality assurance procedures.

~~b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)~~

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2; RACT Plan 234, Condition 1.8)

~~**5. Reporting Requirements:**~~

~~a. The permittee shall report the following information semi-annually to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. The reports shall be postmarked by the 30th day following the end of the reporting period. (§2103.12.k; §2103.12.a.2.D)~~

~~1. Total monthly Fuel Combustion Unit, fuel use, per fuel type;~~
~~2. Cold start information; and~~
~~3. Non-compliance information required to be recorded by Condition V.A.4.b above~~

~~b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)~~

6. Work Practice Standards:

At no time shall the permittee allow Boilers No. 1 or 2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

B. Boilers R1 and R2: B005 & B006

Process Description: Steam production
Facility ID: B005 & B006
Max. Design Rate: 229 MMBtu/hr, each (Heat Input)
Capacity: 229 MMBtu/hr, each (Heat Input)
Raw Materials: Desulfurized coke oven gas
Control Device: NA

1. Restrictions:

~~a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)~~

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. 1or 2, shall not at any time exceed 0.31 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. NO_X emissions from each Boilers No. R1 or R2 shall not exceed the limitations in Table V-B-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-B-1: NO_X Emission Limitations

Process	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler R1	0.31	70.99	310.94
Boiler R2	0.31	70.99	310.94

*A year is defined as any consecutive 12-month period.

~~2. Testing Requirements:~~

~~a. The permittee shall perform emissions testing on Boilers R1 and R2 at least once every two years for NO_X. Such testing shall be in accordance with EPA Methods 7 through 7E or other such methods as approved by the Department. [RACT Plan 234 and §2108.02.e; §2107.05]~~

~~b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 above and Article XXI §2108.02. (§2103.12.h.1)~~

~~3. Monitoring Requirements:~~

~~None except as provided elsewhere in the permit~~

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: (§2103.12.j; 25 Pa Code §129.100)

1. Records of the amount of coke oven gas combusted and the H_2S content of the coke oven gas (daily, monthly and 12 months)
2. Cold starts (date, time and duration of each occurrence);
3. Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

~~b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)~~

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2)

~~**5. Reporting Requirements:**~~

~~a. The permittee shall report the following information semi-annually to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. (§2103.12.k; §2103.12.a.2.D)~~

~~1. Monthly and 12-month data required to be recorded by Condition V.B.4.a above;~~
~~2. Cold start information; and~~
~~3. Non-compliance information required to be recorded by Condition V.B.4.b above~~

~~b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)~~

6. Work Practice Standards:

At no time shall the permittee allow Boiler No. R1 or R2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

C. Boilers T1 and T2: Existing Boiler T1 & T2

Process Description: Steam production
Facility ID: B007 & B008
Max. Design Rate: 156 MMBtu/hr, each (Heat Input)
Capacity: 156 MMBtu/hr, each (Heat Input)
Raw Materials: Desulfurized coke oven gas and natural gas
Control Device: NA

1. Restrictions:

~~a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)~~

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. T1or T2, shall not at any time exceed 0.31 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. NO_X emissions from each Boilers No. T1 or T2 shall not exceed the limitations in Table V-C-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-C-1: NO_X Emission Limitations

Process	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler T1	0.31	40.36	211.02
Boiler T2	0.31	40.36	211.02

*A year is defined as any consecutive 12-month period.

~~2. Testing Requirements:~~

~~a. The permittee shall perform emissions testing on Boilers T1 and T2 at least once every two years for NO_X. Such testing shall be in accordance with EPA Methods 7 through 7E or other such methods as approved by the Department. (RACT Plan 234 and §2108.02.c; §2107.05)~~

~~b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 above and Article XXI §2108.02. (§2103.12.h.1)~~

~~3. Monitoring Requirements:~~

~~None except as provided elsewhere in the permit~~

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers T1 and T2: (§2103.12.j; 25 Pa Code §129.100)

1. Records of the type and amount of fuel combusted and the H_2S content of the coke oven gas (daily, monthly and 12 months)
2. Cold starts (date, time and duration of each occurrence);
3. Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

~~b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)~~

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2)

~~**5. Reporting Requirements:**~~

~~a. The permittee shall report the following information to the Department semi-annually in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. The reports shall be postmarked by the 30th day following the end of the reporting period. (§2103.12.k; §2103.12.a.2.D)~~

~~1. Monthly and 12-month data required to be recorded by Condition V.C.4.a above;~~
~~2. Cold start information; and~~
~~3. Non-compliance information required to be recorded by Condition V.C.4.b above~~

~~b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)~~

6. Work Practice Standards:

At no time shall the permittee allow Boiler No. T1 or T2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

D. Process Equipment Sources

1. Work Practice Standards:

a. At no time shall the permittee operate the following equipment at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; 25 Pa Code §129.99; §2102.04.b.5)

1. Coke Oven Batteries No. 1, 2, 3, 13,1 4, 15, 19, 20, B and C
2. Pushing Emission Control System for the batteries specified in V.D.a.1
3. By-Product Recovery Plant
4. Desulfurization Plant (Scot Plant Incinerator}
5. Wastewater Treatment Plant

b. The coke oven batteries listed in condition V.D.1.a.1 above shall continue to comply with the NESHAP Subpart CCCCC and Subpart L work practice standard. (§63.306; 63.7300; 25 Pa Code §129.99; §2102.04.b.5)

c. The permittee shall not operate C Battery coke ovens unless the PROven® System is maintained and operated in such manner that the collector main is maintained at a negative pressure and each individual oven is maintained at the lowest positive pressure necessary to inhibit leaks of raw coke oven gas to the atmosphere from oven doors, charging port lids, and offtakes. [25 Pa Code §129.99; §2102.04.b.6]

d. 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. [§2105.06; RACT Plan 234; 25 Pa Code §129.99]

e. For the By-Product Plant, the permittee shall: [§2105.06; 25 Pa Code §129.99; §2104.08]

1. The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 61, Subpart V - *National Emission Standards for Equipment Leaks (Fugitive Emission Sources)*. [25 PA Code §129.99]

f. For the desulfurization Plant, the permittee shall: [§2105.06; 25 Pa Code §129.99]

1. Properly maintaining two Claus Plants at the coke oven gas desulfurization facility. 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 heat exchangers in the Vacuum Carbonate Units at the Clairton Works coke oven gas desulfurization facility.
5. Maintaining in good working order spare pumps in the Vacuum Carbonate Units at the coke oven gas desulfurization facility.
6. Good combustion practices.

7. Annual Tune-ups, continued operation as permitted and incineration as permitted.

E. Quench Towers:

Process Description: Water quenching of incandescent coke
Raw Materials: Incandescent coke, water
Control Device: Baffles installed in the quench towers to capture entrained water droplets

1. Work Practice Standards:

a. At no time shall the permittee operate the following quench towers at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (25 Pa Code §129.99; §2102.04.b.5)

Source ID	Description	Rating
P013	Quench Tower No. 1	1,553,805 tons/yr of coal
P015	Quench Tower No. 5	1,637,025 tons/yr of coal
P016	Quench Tower No. 7	2,004,580 tons/yr of coal
P017	Quench Tower B	1,491,025 tons/yr of coal
P046	Quench Tower C	1,379,059 tons/yr of coal
P051	5A Quench Tower	1,270,200 tons/yr of coal
P046	7A Quench Tower	1,555,630 tons/yr of coal

b. The permittee shall be in compliance with the quench tower work practice standards, and operation and maintenance requirements of NEESHAP 40 CFR 63, Subpart CCCCC at all times, except during periods of startup, shutdown, and malfunction as defined in §63.2. [25 Pa Code §129.99; §2103.12.h.6; §63.7295(b) & (c)]

F. Emergency Flare:

1. Work Practice Standards:

a. The permittee properly operates and maintained the emergency flare according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (25 Pa Code §129.99; §2102.04.b.5)

b. The permittee shall maintain and operate the flare according to flare minimization plan that includes (25 Pa Code §129.99; §2102.04.b.5)

1. A listing of all process units and ancillary equipment connected to the flare for each affected flare,
2. An evaluation of the baseline flow to the flares, not including pilot gas flow or purge gas flow.
3. A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring; and a description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring
4. The facility must follow the flare minimization plan and operate all flares in such a manner that minimizes all flaring except during emergencies, shutdowns, startups, turnarounds or essential operational needs, and
5. The plan should be updated periodically to account for changes in the operation of the flares, such as new connections to the flares or the installation of a flare gas recovery system, but the plan needs to be re-submitted to the Department only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline, or installs a flare gas recovery system.

Pages 31 through 32 have been redacted.

ALLEGHENY COUNTY HEALTH DEPARTMENT
AIR QUALITY PROGRAM

April 24 2020

SUBJECT: **Reasonable Available Control Technology (RACT II) Determination**
U.S. Steel Clairton Plant
400 State Street
Clairton, PA 15025-1855
Allegheny County

Installation Permit No. 0052-I020

TO: JoAnn Truchan, P.E.
Section Chief, Engineering

FROM: Hafeez Ajenifuja
Air Quality Engineer

I. Executive Summary

U.S. Steel Clairton Plant is defined as a major source of NO_X and VOC emissions and was subjected to a Reasonable Achievable Control Technology (RACT II) review by the Allegheny County Health Department (ACHD) required for the 1997 and 2008 Ozone National Ambient Air Quality Standard (NAAQS). The findings of the review established that technically and financially feasible RACT would result in the following emissions changes, summarized below.

The PA proposed presumptive RACT does not specify emission rates for combustion units that fire coke oven gas (COG) or fuel blends.

Table 1 Technically and Financially Feasible Control Options Summary for NO_X

Unit ID	Emissions Unit	Financially Feasible Control Option	Current NO_X PTE	RACT II Reduction	Revised NO_X PTE
P001	Underfiring Battery 1	None	336.0	0	336.0
P002	Underfiring Battery 2	None	299.1	0	299.1
P003	Underfiring Battery 3	None	311.2	0	311.2
P007	Underfiring Battery 13	None	236.2	0	236.2
P008	Underfiring Battery 14	None	206	0	206
P009	Underfiring Battery 15	None	255.9	0	255.9
P010	Underfiring Battery 19	None	1,194.80	0	1,194.80
P011	Underfiring Battery 20	None	1,194.80	0	1,194.80
P012	Underfiring Battery B	None	767.7	0	767.7
P046	Underfiring Battery C	None	556.8	0	556.8
P019	Desulfurization Plant	None	3.68	0	3.68
B010	Ammonia Flare	None	19.03	0	19.03
B001	Boiler 1	Lower NO_X limit	1740	142	1,598
B002	Boiler 2	Lower NO_X limit	1285	505	780
B005	Boiler R1	Lower NO_X limit	525	214.06	310.94
B006	Boiler R2	Lower NO_X limit	525	214.06	310.94
B007	Boiler T1	Lower NO_X limit	358	146.18	211.82
B008	Boiler T2	Lower NO_X limit	358	146.18	211.82
Total			**10,172**	**1,367**	**8,805**

Table 2 Technically and Financially Feasible Control Options Summary for VOC

Unit ID	Emissions Unit	Financially Feasible Control Option	Current VOC PTE	RACT II Reduction	Revised VOC PTE
P001	Underfiring Battery 1	None	4.8	0	4.8
P002	Underfiring Battery 2	None	4.4	0	4.4
P003	Underfiring Battery 3	None	3.8	0	3.8
P007	Underfiring Battery 13	None	3.4	0	3.4
P008	Underfiring Battery 14	None	3.3	0	3.3
P009	Underfiring Battery 15	None	3	0	3
P010	Underfiring Battery 19	None	10.4	0	10.4
P011	Underfiring Battery 20	None	10.4	0	10.4
P012	Underfiring Battery B	None	11	0	11
P046	Underfiring Battery C	None	7.8	0	7.8
P019	Desulfurization Plant	None	4.34	0	4.34
B010	Ammonia Flare	None	0.49	0	0.49
P021	Coke Byproduct Recovery Plant	None	58.0	0	68.0
P044	Light Oil Barge Loading	None	0.75	0	0.75
B001	Boiler 1	None	18.31	0	18.31
B002	Boiler 2	None	11.59	0	11.59
B005	Boiler R1	None	5.52	0	5.52
B006	Boiler R2	None	5.52	0	5.52
B007	Boiler T1	None	3.76	0	3.76
B008	Boiler T2	None	3.76	0	3.76
Total			**184.4**	0	**184.4**

II. Regulatory Basis

ACHD requested all major sources of NO_X (potential emissions of 100 tons per year or greater) and all major sources of VOC (potential emissions of 50 tons per year or greater) to reevaluate NO_X and/or VOC RACT for incorporation into Allegheny County's portion of the PA SIP. The U.S. Steel Clairton Plant requested a case by case RACT II determination under 25 Pa Code 129.99 for units P001, P002, P003, P007, P008, P009, P010, P021, P044 B001, B002 and B005, B006, B007, B008. This document is the result of ACHD's determination of RACT for these emission sources based on the materials submitted by the subject source and other relevant information.

III. Facility Description, Existing RACT I, Sources of NO_X, and Sources of VOC

U.S. Steel Clairton Works is the largest by-products coke plant in North America. Clairton Works operates 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, approximately 225 million cubic feet of coke oven gas are 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 includes 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 35 tons of elemental sulfur, and 50 tons of anhydrous ammonia. There are six (6) Boilers at Clairton, which are used to generate steam, heat, and electricity for the plant. The two (2) primary fuels for the boilers are Coke Oven Gas, (COG), and Natural Gas (NG). On December 30th, 1996 the facility entered into a consent decree with the Department to meet RACT I obligations under RACT Order No. 234. RACT Order 234 was approved as RACT by EPA in 2001 (66 FR 52511). The RACT I requirements are listed in Table 3 below:

Table 3 RACT I Summary

Source	RACT Order 234 Condition No.	RACT I Requirement
Coke Batteries No. 1,2,3,13,14,15,19,20, B and Battery C; Pushing Emission Control System for the batteries; Boilers 1,2, R1, R2, T1 and T2; By-Products Plant Coke Oven Gas Blanketing System and all process units blanketing by this system; Scot Plant Incinerator; and Wastewater Treatment Plant	I.1.1	At no time shall USX operate the following equipment at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices, with the exception of actions to mitigate emergency conditions.
Boiler Nos. 1, 2, R1, R2, T1 and T2	I.1.2	Boiler 1 NO_X limits: 0.54 MMBtu, 1,740 tons/yr; Boiler 2 NO_X limits: 0.54 MMBtu, 1,285 tons/yr; Boiler R1 NO_X limits: 0.54 MMBtu, 525 tons/yr; Boiler R2 NO_X limits: 0.54 MMBtu, 525 tons/yr; Boiler T1 NO_X limits: 0.54 MMBtu, 358 tons/yr; Boiler T2 NO_X limits: 0.54 MMBtu, 358 tons/yr;
Boiler Nos. R1, R2, T1 and T2	I.1.3	Boilers shall perform NO_X emissions stack test every two (2) years to determine compliance with NOx limit in lb/MMBtu
Boiler Nos. 1 and 2	I.1.4	Boilers shall use CEMS.
Boiler Nos. 1 and 2	I.1.5	Compliance with NO_X limits determine by 30-day rolling average for lbs/MMBtu and 12-month rolling average for tons/yr limits.
By-Products Plants	I.1.6	Properly maintain and operate the clean coke oven gas blanketing system at all times. Incinerate all VOC emissions processed by the blanketing system in the coke batteries or boilers.
Boiler Nos. 1 and 2	I.1.7; I.1.8	The permittee shall retain and maintain all appropriate records to demonstrate compliance with the requirements of both Section 2105.06 of Article XXI and this Order.

Case-by-Case RACT II and Existing RACT I Limits

Table 4 Facility Sources Subject to NO_X Case-by- Case RACT II and Existing RACT I Limits

Source ID	Description	Rating	NO_X PTE (TPY)	NO_X Limit (RACT I)	Proposed NO_X PTE	NO_X Limit (RACT II)
B001	Boiler No. 1	760 MMBtu/hr	1,740	0.54 lbs/MMBtu	1,598	0.48 lbs/MMBtu
B002	Boiler No. 2	481 MMBtu/hr	1,258	0.54 lbs/MMBtu	780	0.37 lbs/MMBtu
B005	Boiler R1	229 MMBtu/hr	525	0.54 lbs/MMBtu	310.94	0.31lbs/MMBtu
B006	Boiler R2	229 MMBtu/hr	525	0.54 lbs/MMBtu	310.94	0.31lbs/MMBtu
B007	Boiler T1	156 MMBtu/hr	358	0.54 lbs/MMBtu	211.82	0.31lbs/MMBtu
B008	Boiler T2	156 MMBtu/hr	358	0.54 lbs/MMBtu	211.82	0.31lbs/MMBtu
P001	Underfiring Battery 1	517,935 tons/yr of coal	336.0	N/A	336.0	Comply with NEESHAP Subpart CCCCC and Subpart L work practice standard 63.7300 and 63.306 Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P002	Underfiring Battery 2	517,935 tons/yr of coal	299.1	N/A	299.1	
P003	Underfiring Battery 3	517,935 tons/yr of coal	311.2	N/A	311.2	
P007	Underfiring Battery 13	545,675 tons/yr of coal	236.2	N/A	236.2	
P008	Underfiring Battery 14	545,675 tons/yr of coal	206	N/A	206	
P009	Underfiring Battery 15	545,675 tons/yr of coal	255.9	N/A	255.9	
P010	Underfiring Battery 19	1,002,290 tons/yr of coal	1,194.80	N/A	1,194.80	
P011	Underfiring Battery 20	1,002,290 tons/yr of coal	1,194.80	N/A	1,194.80	
P012	Underfiring Battery B	1,491,025 tons/yr of coal	767.7	N/A	767.7	
P046	Underfiring Battery C	1,379,059 tons/yr of coal	556.8	N/A	556.8	PROven System; Comply with NEESHAP Subpart CCCCC and Subpart L work practice standard 63.7300 and 63.306 Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P019	Desulfurization Plant	6,394,800 tons of coke	31.45	N/A	31.45	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
B010	Ammonia Flare	12.5 MMBtu/hour	19.03	N/A	19.03	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
	Pushing Emission for the batteries					

Table 5 Facility Sources Subject to VOC Case-by-Case RACT II and Existing RACT I Limits

Source ID	Description	Rating	VOC PTE (TPY)	VOC Limit (RACT I)	Proposed VOC PTE	VOC Limit (RACT II)
B001	Boiler No. 1	760 MMBtu/hr	18.31	N/A	18.31	N/A
B002	Boiler No. 2	481 MMBtu/hr	11.59	N/A	11.59	N/A
B005	Boiler R1	229 MMBtu/hr	5.52	N/A	5.52	N/A
B006	Boiler R1	229 MMBtu/hr	5.52	N/A	5.52	N/A
B007	Boiler T1	156 MMBtu/hr	3.76	N/A	3.76	N/A
B008	Boiler R1	156 MMBtu/hr	3.76	N/A	3.76	N/A
P001	Underfiring Battery 1	517,935 tons/yr of coal	4.8	N/A	4.8	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices.
P002	Underfiring Battery 2	517,935 tons/yr of coal	4.4	N/A	4.4	
P003	Underfiring Battery 3	517,935 tons/yr of coal	3.8	N/A	3.8	
P007	Underfiring Battery 13	545,675 tons/yr of coal	3.4	N/A	3.4	
P008	Underfiring Battery 14	545,675 tons/yr of coal	3.3	N/A	3.3	
P009	Underfiring Battery 15	545,675 tons/yr of coal	3	N/A	3	
P010	Underfiring Battery 19	1,002,290 tons/yr of coal	10.4	N/A	10.4	
P011	Underfiring Battery 20	1,002,290 tons/yr of coal	10.4	N/A	10.4	
P012	Underfiring Battery B	1,491,025 tons/yr of coal	11	N/A	11	
P046	Underfiring Battery C	1,379,059 tons/yr of coal	7.8	N/A	7.8	PROven System & Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P019	Desulfurization Plant	6,394,800 tons of coke	4.34	N/A	4.34	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P044	Light Oil Barge Loading	55,000,000 gallons/yr	8.74	N/A	8.74	Vapor Recovery; Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
B010	Ammonia Flare	12.5 MMBtu/hour	0.49	N/A	0.49	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices; Flare Minimization
P021	Coke Byproduct Recovery Plant		58	N/A	58	Comply with work practice standard MACT 61, Subpart V (LDAR); Gas Blanketing & Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices

Table 6	Facility Quench Tower Subject to the CASE-BY CASE RACT II per PA Code 129.99				
Source ID	**Description**	**Rating**	**NO_X PTE (TPY)**	**VOC PTE (TPY)**	**Presumptive RACT Requirement (**25 Pa Code Section 129.99) & Workpractice Standard 63.7295(b)
P013	Quench Tower No. 1	1,553,805 tons/yr of coal	1.55	9.71	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P015	Quench Tower No. 5	1,637,025 tons/yr of coal	1.88	9.17	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P016	Quench Tower No. 7	2,004,580 tons/yr of coal	1.70	13.83	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P017	Quench Tower B	1,491,025 tons/yr of coal	2.89	9.83	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P046	Quench Tower C	1,379,059 tons/yr of coal	2.77	11.07	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P051	5A Quench Tower	1,270,200 tons/yr of coal	1.88	10.80	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P046	7A Quench Tower	1,555,630 tons/yr of coal	1.70	13.22	Workpractice Standard NESHAP Subpart CCCCC- 63.7295(b) Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices

IV. RACT Determination

Two detailed RACT Reviews were performed to evaluate the U.S. Steel Clairton facility; one was performed by U.S. Steel Clairton Plant, and one by Allegheny County Health Department (ACHD). Both submissions were considered in the final RACT disposition for the Facility and findings from each were incorporated into the ACHD RACT II Determination.

COKE BATTERY UNDERFIRE COMBUSTION STACKS (P001-P003; P007-P012)

Based on review of the referenced documents, literature available from vendors, engineering judgment and experience, the following NO_X control options were identified as potentially technically feasible for the batteries at U.S Steel Clairton facility:

1. LNB / ULNB -No, these are direct fired heating systems.
2. FGR -No, 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.
3. RSCR -No, not proven on coke batteries and rerouting would be too extensive.
4. SNCR-Yes, with preheating of the exhaust gas.
5. SCR - No, due to large potential outlet temperature and volumetric flowrate changes.

Coke batteries are operated at a relatively high excess air level compared to some other combustion processes. Excess air in coke ovens is needed to maintain compliance with other battery stack emissions regulations, namely the Article XXI and NESHAPs requirements. A source of emissions from battery stacks is coke oven gas leakage from the oven chambers into the combustion flues. This leakage typically occurs at local sites where imperfection in the oven walls exist allowing some leakage. Excess air allows the leaking gas to be efficiently burned instead of being emitted from the stack as particulate matter or VOC. Clairton Works' procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. In this balance, minimizing excess air is important as a fuel conservation method. Also, 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. Additionally, operation with sufficient excess air is needed to assure complete combustion of the COG that can be subject to heating value variability.

Pollution prevention/combustion modifications - LNB, FGR, are not technically feasible control options for Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20. The underfiring process, by virtue of its design, is ill-suited for retrofit emission reductions techniques for the following reasons:

- While other combustion processes (e.g. that of a boiler) can be highly tuned (via changes to over- and under-fire air, air-to-fuel ratios, exhaust recirculation etc.) to reduce emissions or accommodate changes in back pressure (created by add-on pollution control), a coke battery's underfiring system cannot. While the principle of all coke ovens is the same, each coke oven and oven operation is unique due to wide variations in the geometry of the combustion chambers, the combustion variables of fuel and air mixtures, temperature, humidity, and other factors.

- With burners and heating/exhaust flues distributed throughout the battery oven walls and infrastructure, an entire battery would need to be dismantled and rebuilt to accommodate modifications to the underfiring system. Even if such an endeavor was completed, there is little information available regarding the effectiveness of the NO_X control that would be achieved.

- The underfiring process has a very large volumetric exhaust flow rate (approximately 56,000-102,000 dscf/min) and relies on certain flame temperatures and flame lengths to adequately produce coke products. Modifications to the underfiring system are likely to compromise requisite flame, air flow characteristics, system backpressure, and the quality of the coke produced.

- Clairton's standard operating procedures optimize the balance among oven wall protection. Coke batteries are operated at a relatively high excess air level compared to some other combustion processes. Excess air in coke ovens is needed to maintain compliance with other battery stack emissions regulations, namely the Article XXI and NESHAPs requirements. A source of emissions from battery stacks is coke oven gas leakage from the oven chambers into the combustion flues. This leakage typically occurs at local sites where imperfection in the oven walls exist allowing some leakage. Excess air allows the leaking gas to be efficiently burned instead of being emitted from the stack as particulate matter or VOC. Clairton Works procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. In this balance, minimizing excess air is important as a fuel conservation method. Also, 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. Additionally, operation with sufficient excess air is needed to assure complete combustion of the COG that can be subject to heating value variability.

- Staged combustion for a coke battery underfiring process has been successfully designed and utilized by Battery C. However, that battery was originally designed with the pollution prevention technology and permitted for construction in 2008.

- It is not possible to reduce the temperature of the preheated combustion air or the fuel. All of the batteries are constructed of refractory brick, and the regenerators are beneath the ovens and heating flues and are an integral part of the structure. Fuel passing through the gun-flues in Batteries 1-3, 13-15 and B or the risers in Batteries 19 and 20 is heated by the surrounding ovens, heating flues and regenerators. Revising the path of the fuel gas or combustion air to the burners would require complete reconstruction of the battery.

Add-on Pollution Controls (SCR and SNCR)

SCR: Clairton's coke battery combustion and exhaust system does not operate with exhaust gas temperatures and airflows in the range where SCR can be effectively utilized. The average flue gas temperature of the combustion stack is approximately 493 °F; between 100 and 300 degrees cooler than what would be needed to ensure effective operation of an SCR. Because of the massive exhaust airflow, preheating the exhaust would require additional fuel combustion that would significantly offset the emissions reductions achieved by the SCR.

According to literature research and discussions with vendors, it was determined that regenerative SCR (RSCR) has primarily been utilized to control NO_X from relatively small biomass-fired boilers. There is no evidence that RSCR has been applied to a coke battery underfiring system. In addition, the retroactive installation of a post-combustion NO_X control, like SCR, would likely increase back pressure on the system and cause combustion process control to become erratic. This kind of process upset would likely result in increased emissions, poor coke quality and potentially compromise the integrity of the battery and the Clairton's ability to operate it safely. As a result, SCR is not technically feasible.

SNCR: There are no known applications, demonstrated or commercially operational, of SNCR to a coke oven battery underfiring/combustion system. 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. As a result, SNCR is not technically feasible.

Battery C Emission Controls

A key component in the control of emissions from C Battery, as discussed in the BACT analysis submitted by U. S. Steel, is the PROven® (Pressure Regulated Oven) system. The PROven® system maintains the oven at a low positive pressure throughout the coking cycle preventing or greatly reducing emissions during coal charging, and from oven doors, offtakes, collector main and the combustion stack.

The PROven® system is an electronic control system that individually controls the pressure in each individual oven depending on the stage of coking that each oven is experiencing. Leaks from doors and lids, emissions from soaking due to poor seal between the oven and collector main, and offtake leaks will also be minimized since the emissions will be conveyed to the collector main which is maintained at a negative pressure. NO_X emissions will be controlled using a low NO_X heating system. The hood's capture efficiency is guaranteed at 90%.

The PROven® system will be especially effective in minimizing oven-to-flue leakage of raw coke oven gas, thus reducing emissions of VOCs. VOC emissions is also minimized through the employment of the PROven® system in combination with the staged air combustion system.

NO_X emissions is 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. Therefore, the Department has determined that RACT II for C battery is the operation of the installed PROven System.

BATTERIES QUENCH TOWER

The facility's quench towers are subject to coke oven batteries NEESHAP, Subpart CCCCC workpractice standard 63.7295(b). This work practice represent industry standard and are technically and economically feasible as the facility is already implementing it. The applicable requirements listed below have been incorporated into the Title V operating permit and has also been referenced in the RACT II IP20.

1. The permittee shall equip 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.

2. The permittee shall wash the baffles in each quench tower once each day that the tower is used to quench coke, except as specified in the following conditions:

    a. You are not required to wash the baffles in a quench tower if the highest measured ambient temperature remains less than 30 degrees Fahrenheit throughout that day (24-hour period). If the measured ambient temperature rises to 30 degrees Fahrenheit or more during the day, you must resume daily washing according to the schedule in your operation and maintenance plan.
    b. You must continuously record the ambient temperature on days that the baffles were not washed.

3. Inspect each quench tower monthly for damaged or missing baffles and blockage.

4. Initiate repair or replacement of damaged or missing baffles within 30 days and complete as soon as practicable.

BOILERS

The six facility boilers were reviewed for potential control of NO_X emissions, in accordance with the applicable control technologies. Boiler 1 is a cyclone type rated at 760 MM BTU/hr heat input, boiler 2 is four-wall-fired rated at 480 MMBTU/hr, and R1, R2, T1 and T2 are packaged wall-fired units (R1 and R2 are each rated at 229 MMBTU/hr, and T1 and T2 are each rated at 156 MMBTU/hr). Boilers number R1 and R2, and T1 and T2 are identical units by design and size, therefore only one boiler of each set was reviewed (since the results for the identical boiler would be the same). The operational difference amongst the boilers is potential variation in steam output that is required on a yearly basis. Boilers #1 and 2 operate continuously throughout the year to provide the primary steam demands; they are typically only shutdown for annual outages (maintenance). Based on normal operations steam demands, on a yearly average basis Boilers 1 and 2, is between approximately 50-75% of rated load. Boiler 1 is normally operated at a base-load (consistent supply rate) with Boiler 2 operating in the swing-load mode (remainder of the load requirements at any given time). When either Boiler 1 or 2 are down, the four remaining boilers (R1, R2, T1 and T2) are operated to provide the required steam demands. The steam production capability for combination of the four boilers (R1, R2, T1 and T2} is approximately equivalent to the steam capability of Boiler #1. An Annual outage are planned during periods of lower steam demand (e.g. summer} so that during annual outages less steam is required throughout the plant; typically, boilers R1, R2 and T1 operate near rated load and T2 is operated as a swing load. Annual outages occur for a duration of approximately 14 to 30 days per year. However, if an unexpected outage of either Boiler #1 or 2 occurs, the remaining four boilers will be operated to supplement the steam demand. In light of this, actual annual emissions from the four boilers are significantly lower than their potential annual emissions. This flexibility, to operate any of boilers R1, R2, T1 and T2 on an unlimited basis at any given time, is necessary to assure that sufficient steam supply will always be available (in case of an unexpected extensive or permanent shutdown of Boilers #1 or 2).

Each of the six boilers is limited to a NO_X short term emission rate of 0.54 lbs/MMBTU, based on the previous 1996 RACT Order I. Continuous Emission Monitors (CEMS) have been installed on Boilers 1 and 2 for NO_X and O_2 monitoring. A review of CEMS data for Boilers 1 and 2 indicates that the boilers annual average NO_X emission rates are typically half or less of the permitted limits, indicating that the boilers are being operated effectively for the age, types and size of these boilers. The most recent stack test for boilers R1, R2, T1 and T2 indicate that the NO_X emission rates ranges from 0.132 to 0.2 lbs/MMBTU. All test results are based on firing COG, the primary fuel. It is assumed that emission rates would be approximately equivalent while firing natural gas. These NO_X emission rates for boilers R1, R2, T1 and T2 are generally lower than emission rates commonly associated with packaged natural gas fired boilers that employ low NOx burners. Burner manufactures have indicated (quoted) that replacement burners would not achieve a reduction in NO_X, based upon the actual emission rates that are currently being achieved, for Boiler #2, R1, R2, T1 and T2. Boiler 1 is currently operating at or below burner manufacturer's indicated rates during ozone season. Additionally, due to the low excess air already being achieved, FGR or additional OFA will not be feasible; further suppression of excess air by these means would likely terminate the flame or pilot (which has been seen in cases like this before). Greater reduction in excess air would also lead to incomplete combustion, resulting in an increase in VOC and opacity emissions. In a retrofit situation, the boiler design (i.e., windbox, FD/ID fans, damper positions, burner locations, etc.) would have to be modeled by computer simulation to identify the NO_X emission rates that can be achieved through retrofitting, and whether it could actually produce lower emission rates. Boiler/burner vendors would not quote potential emission reduction for such changes due to these issues. Therefore, pre-combustion controls were not reviewed further for Boilers #2, R1, R2, T1 and T2.

Addition of SCR or SNCR can reduce NO_X emissions. SCR is expected to be capable of reducing NO_X emissions by 80% and SNCR by 45%. However, vendors indicated that guarantees could not be provided until testing of the alternative gas was completed, due to the potential formation of byproducts such as silanes. Nonetheless a cost effectiveness analysis was performed on one representative boiler based upon the referenced NO_X reduction efficiency versus the annual potential emissions of 1,740 tons/yr. The exhaust gas streams will also have to be pre-heated before they are directed to the SCR or SNCR units, since the exhaust gases are generally less than 400°F. Results for this analysis will be the same as for the other boilers.

Meanwhile, the PA proposed presumptive RACT does not specify emission rates for combustion units that fire COG or fuel blends and as enumerated above, the boilers annual average NO_X emission rates are typically half or less of the permitted RACT I limits. Consequently, the Department has determined the following to be RACT II limits for the six boilers:

Table 7

Boiler	Lbs/MMBtu	Tons/yr
No. 1	0.48	1,598
No. 2	0.37	780
R1	0.31	310.94
R2	0.31	310.94
T1	0.31	211.82
T2	0.31	211.82

This conclusion for boilers 1 & 2 is based on a review of the 2014-2019 daily CEM data, which indicated maximum 30-day NO_X averages of 0.40 lb/MMBtu for boiler 1 (January 2015) and 0.31 lb/MMBtu for boiler 2 (November 2018). Factoring a 20% increase for variability, the RACT II NO_X limits are 0.48 lb/MMBtu for Boiler 1 and 0.37 for

Boiler 2 using a 30-day rolling average (as per 25 Pa Code 129.100(a)(1)). Boilers R1, R2, T1 and T2 are based on the 2012 average stack test of boiler R1 and a 20% increase for variability. The quarterly CEM monitoring and bi-annual stack testing required by the facility's Title V operating permit conditions shall be used to demonstrate compliance with the proposed RACT II limits.

DESULFURIZATION PLANT (INCINERATOR):

Based on review of the referenced documents, literature available from vendors, engineering judgment and experience, the following NO_X control options were identified as potentially technically feasible for the desulfurization plant at U.S Steel Clairton facility:

1. LNB / ULNB - No, the incinerator burner nozzles, oxygen and fuel feed, and combustion chambers are already inherently designed for NO_X control; no changes to these units are available without impact on emission reduction performance of other pollutants (which could cause a violation of the performance requirements).
2. FGR -No, the incinerator is a regenerative type unit. As such, it already employs flue gas recirculation as part of the system design. The incinerator is not designed to handle any additional volumetric flow.
3. RSCR - No, RSCR has not been proven on incineration units. No vendor guarantees would be provided.
4. SNCR-Yes, with preheating of the incinerator exhaust gas.
5. SCR- Yes, with supplemental heat reduction of the incinerator exhaust gas.

NO_X emissions are produced from the waste gas incineration process. As previously indicated, the incinerator is a regenerative type unit, and no pre-combustion controls are available that would affect NO_X emission rate. However, the incinerator gas exhaust can be treated with SCR or SNCR. SCR application would require the pre-absorption of heat since the incinerator exhaust can range from 1,500 to 2,000°F. The exhaust gas would have to be lowered to a rate of at least 1,200°F to enable the use of the high temperature catalyst. A heat exchanger would need to be installed to add heat (as needed} to the exhaust gas for application of SNCR, as the gas inlet must be above at least 1,600°F.

Tail gas from the desulfurization unit is exhausted to the SCOT Plant thermal oxidizer. Thermal oxidation is considered to be the most effective means of reducing VOCs. Based on review of the referenced documents, literature available from vendors, engineering judgment and experience, the following VOC control options were identified as potentially technically feasible for the desulfurization plant at U.S Steel Clairton facility:

1. Thermal Oxidization
2. Carbon Adsorption
3. Catalytic Oxidization
4. Refrigerated Condensation
5. Flaring
6. Absorption (Scrubbing)

Each identified control option is technically feasible.

The uncontrolled VOC PTE of the desulfurization plant is 398 ton/yr. However, the existing desulfurization plant /SCOT Plant incinerator has a VOC PTE of approximately 5.78 tons/yr. (The existing DP/SCOT Plant incinerator is an example of thermal oxidation.) The potential incremental VOC reduction (ton/yr.) of any of the technically feasible control options is therefore so low that none of those options are economically feasible. As a result, no additional analyses were completed.

The Desulfurization Plant (which includes the SCOT Plant) shall continue the use of SCOT Plant Incinerator. Operation of the incinerator shall be consistent with the current requirements established for the unit in Clairton's Title V permit. In addition, the SCOT Plant Incinerator and the Desulfurization Plant shall be properly operated and maintained in accordance with good engineering and air pollution control practices. Good engineering practices include:

1. Properly maintaining two Claus Plants at the coke oven gas desulfurization facility. 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 heat exchangers in the Vacuum Carbonate Units at the Clairton Works coke oven gas desulfurization facility.
5. Maintaining in good working order spare pumps in the Vacuum Carbonate Units at the coke oven gas desulfurization facility.
6. Good combustion practices.
7. Annual Tune-ups, continued operation as permitted and incineration as permitted.

FLARES

The flares at Clairton Works operate on an emergency basis only and burner packages and FGR that limit NO_X are not amenable to such flares; add-on controls cannot be used on flares. The flares combust excess de-sulfurized COG that cannot be used as fuel in its boilers or for battery underfiring. In this capacity, an EF primarily functions as VOC control and a safety device. Without them, excess COG would accumulate near ground level and create a significant fire/explosion hazard. The emergency flares are open flares, i.e., are not enclosed, and operate with a VOC destruction efficiency of 99 percent.

In general, reductions of emissions from flares are based on good engineering practices and on minimization of fuel burned. These controls include Good Engineering Practices and a Flare Minimization Plan. Minimizing flared COG is already a standard operating practice for Clairton. ACHD has determined that NOx RACT for the Emergency Flares is the development and implementation of a flare minimization plan.

1. A listing of all process units and ancillary equipment connected to the flare for each affected flare,
2. An evaluation of the baseline flow to the flares, not including pilot gas flow or purge gas flow,
3. A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring; and a description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring
4. The facility must follow the flare minimization plan and operate all flares in such a manner that minimizes all flaring except during emergencies, shutdowns, startups, turnarounds or essential operational needs, and
5. The plan should be updated periodically to account for changes in the operation of the flares, such as new connections to the flares or the installation of a flare gas recovery system, but the plan needs to be re-submitted to the Department only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline, or installs a flare gas recovery system. In addition, the flares shall be installed, maintained, and operated in accordance with manufacturer specifications, and good engineering and air pollution control practices for minimizing emissions.

BY -PRODUCTS PLANT

As indicated in the previous RACT analysis, the by-products plant emissions are controlled by the gas blanketing system, which controls over 98% of the VOCs. The gas blanketing system and LDAR (61, Subpart V) is considered to be RACT for this source.
The Light Oil Barge Loading facility is presently 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.

V. RACT Summary

The proposed RACT II limits listed in the Table 1 of this document above supersede the relevant conditions of Plan Approval Order and Agreement #235 (RACT I), issued December 30, 1996. As shown in the Table 8 below, The proposed RACT II conditions are at least as stringent as those from RACT I. Other RACT I conditions not affected by RACT II remain in effect.

Table 8: RACT I vs. RACT II NO_X Emission Limits

Unit Description	Equipment Status Since RACT I Order	RACT I NO_X Emission Limit (lb/MMBtu)	RACT II NO_X Emission Limit (lb/MMBtu)
Boiler No. 1	Active – Remains on site	0.54	0.47
Boiler No. 2	Active – Remains on site	0.54	0.37
Boiler No. 13	Shut Down	0.54	NA
Boiler No, 14	Shut Down	0.54	NA
Boiler R1	Active – Remains on site	0.54	0.31
Boiler R2	Active – Remains on site	0.54	0.31
Boiler T1	Active – Remains on site	0.54	0.31
Boiler T2	Active – Remains on site	0.54	0.31

Table 8: RACT II Emission Reduction Summary

Based on the findings in this RACT analysis, the U.S. Clairton Plant emissions can be summarized as follows:

Table 9	RACT II Emission Reduction Summary	
NO_X Potential Emissions (tpy)		
Current PTE	**RACT Reduction**	**Revised PTE**
10,172	**1,367**	**8,805**
VOC Potential Emissions (tpy)		
Current PTE	**RACT Reduction**	**Revised PTE**
184.4	0	**184.4**

As shown in Table 9 above, the new RACT II conditions reduce 1,367 tons per year of potential NO_X emissions and 0 tons per year of potential VOC emissions from the U.S. Steel Clairton facility.

VI. RACT II Permit Conditions

Table 10

Source ID	Description	Permit Condition 0051-I020	RACT II Regulations
B001-B002	Boilers 1 and 3	Condition V.A.1.b Condition V.A.1.c Condition V.A.1.d Condition V.A.1.e Condition V.A.2.a Condition V.A.3.a Condition V.A.4.a Condition V.A.4.c Condition V.A.6.a	25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.99
B005-B006	Boilers R1 and R2	Condition V.B.1.b Condition V.B.1.c Condition V.B.4.a Condition V.B.4.c Condition V.B.6.a	25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.100 25 PA Code §129.100
B007 & B008	Boilers T1 and T2	Condition V.C.1.b Condition V.C.1.c Condition V.C.4.a Condition V.C.4.c Condition V.C.6.a	25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.100 25 PA Code §129.100
P001-P003	Coke Oven Batteries 1-3	Condition V.D	25 PA Code §129.99
P004-P006	Coke Oven Batteries 13-15	Condition V.D	25 PA Code §129.99
P010-P011	Coke Oven Batteries 19 and 20	Condition V.D	25 PA Code §129.99
P012	Coke Oven Battery B	Condition V.D	25 PA Code §129.99
P019	Desulfurization Plant (SCOT Plan)	Condition V.D	25 PA Code §129.99
P021	Coke By-Product Recovery Plant	Condition V.D	25 PA Code §129.99
P046	Coke Oven Battery C	Condition V.D	25 PA Code §129.99
	Quench Towers	Condition V.E.1.a Condition V.E.1.b	25 PA Code §129.99
	Emergency Flare	Condition V.F.1.a Condition V.F.1.b	25 PA Code §129.99 25 PA Code §129.99

ALLEGHENY COUNTY HEALTH DEPARTMENT
Air Quality Program

SUMMARY OF PUBLIC COMMENTS AND DEPARTMENT RESPONSES ON THE PROPOSED ISSUANCE OF UNITED STATES STEEL CORPORATION INSTALLATION PERMIT NO. 0052-I020

[Notice of the opportunity for public comment appeared in the legal section of the Pittsburgh Post-Gazette on February 6, 2020. The public comment period ended on March 17, 2020]

1. **Comment:** U.S. Steel respectfully disagrees with the Department's conclusions and derivation of the case-by-case RACT limits. The proposed RACT limits do not appropriately consider all fuel operating scenarios for the units, and do not reflect operations in periods of time when a greater proportion of natural gas is combusted at the boilers vs. coke oven gas. Any RACT limits need to consider fuel operating scenarios that are different than what ACHD used in its analysis. In addition, while U. S. Steel believes that using a larger proportion of available data to develop limits is appropriate, we respectfully disagree that it is appropriate to use 2013 average annual CEM data and reduce it to a 30-day rolling average - even with an adjustment for variability- as this in itself does not indicate that the limit is achievable over every rolling 30-days, or that it was indeed achieved during every rolling 30-days in the year used to derive the limit. The limits derived during RACT I in 1996 and adopted in the Plan Approval Order and Agreement by Consent No. 234 remain appropriate and correctly considered the fuel burning scenarios that could be incurred for the subject combustion sources at the Clairton Plant. U. S. Steel respectfully identifies that while ACHD notes that the notice of the permit action is being provided pursuant to Article XXI §2102.05.c and §2103.21.c, this action is not being taken by ACHD in response to action regarding a permit application; and U. S. Steel respectfully believes the Department does not have the authority to unilaterally issue an installation permit that was not preceded by a permit application from the source. U.S. Steel notes that Article XXI §2102.04(b) provides: "The Department shall not issue any Installation Permit unless it has complied with all applicable requirements under this Article for public notice and received a complete application. (1 Commenter)

   Response: The Department partially agrees and partially disagrees with the commenter. The commenter asserts that the Department did not consider all fuel burning scenarios when proposing the NO_X emission limits for Boilers No. 1, 2, R1, R2, T1 and T2. However, the RACT II evaluation determined though the examination of historical CEMS data for Boilers No. 1 and 2 that the boilers annual average NO_X emission rates are typically half of the permitted limits, indicating that the boilers are being operated effectively for the age, types and size of these boilers. During that time, US Steel Clairton was free to burn any combination of natural gas and coke oven gas. The Department utilized relevant and available data and reasonably evaluated the feasibility of the proposed NO_X emission limits for these boilers.

   The Department re-evaluated the proposed NO_X limit for Boilers 1 and 2 based on the CEM data from 2014-2019 that included daily and 30-day averages for each boiler. The maximum 30-day average NO_X emission rates for Boilers 1 and 2 during that time period were 0.40 and 0.31 lb/MMBtu, respectively. The Department has revised the proposed short-term and long-term emission limits for Boiler 1 from 0.34 to 0.48 lb/MMBtu and Boiler 2 from 0.34 to 0.37 lb/MMBtu using a 30-day rolling average. The CEMs data, calculated using a 30-day rolling average, demonstrates that the proposed NOx emission limits are reasonable and achievable. The most recent stack test for Boilers No. R1, R2, T1 and T2

indicate that the NO_X emission rates ranges from 0.132 to 0.2 lbs/MMBtu, which demonstrates that the proposed NO_X emission limits are reasonable and achievable.

The commenter also states that the Department exceeded its authority by imposing limits more stringent than the presumptive RACT limits. Given that there are no presumptive RACT requirements in the Pennsylvania regulations for the US Steel Clairton boilers because there is no current presumptive RACT source category that applies to these boilers, it is not possible to compare the ACHD NO_X emission limits for Boilers No. 1, 2, R1, R2, T1 and T2 with any Pennsylvania presumptive RACT requirement. The case by case NO_X emission limits developed for these boilers were warranted because there was no Pennsylvania presumptive RACT requirement applicable (129.99(b)) and are appropriately assessed under the RACT procedures described in 25 Pa. Code 129.99(d).

2. **Comment:** In "TABLE V-A-1: NO_X Emission Limitations", please remove the column titled "Maximum Heat Input Capacity, MM Btu/hr". Heat input is not a NO_X emission limit and is duplicative. The boilers' heat input is listed in V. A. (1 Commenter)

   Response: The Department made the requested change.

3. **Comment:** The case-by-case RACT reviews performed by U. S. Steel and ACHD for Boilers No. 1 and No. 2, Boilers Rl and R2, and Boilers Tl and T2 showed no technologically and economically feasible options, and thus no new limits should be adopted. As ACHD has confirmed, the Clairton Boilers are not subject to any presumptive RACT limits or requirements under 25 Pa. Code section 129.97 and therefore are required under 25 Pa. Code Section 129.99 to propose a source specific RACT limit based on the evaluation of technologically and economically feasible controls. Since no controls were identified through the process, the final RACT determination should have concluded that no technologically and economically feasible options are available and the existing RACT determinations and limits will remain in place. U. S. Steel requests re-instituting the limits provided in RACT Order No. 234. (1 Commenter)

   Response: The Department does not agree with the commenter's assertion that no new RACT limits should be adopted because case-by-case reviews for certain units at the facility showed no technically and economically feasible options.

   The commenter correctly refers to EPA's approval of Pennsylvania's RACT SIP and 25 Pa. Code 129.99 that the alternative RACT emission limit be "based on the feasibility evaluation of reasonably available controls…" and "…on the evaluation of technologically and economically feasible controls." The Department agrees with the commenter that no technically and economically feasible physical controls were identified as RACT, however, the commenter incorrectly concludes that if no physical controls were identified then previously existing RACT limitations from 2001 should remain in place. To the contrary, the current RACT evaluation required under the Clean Air Act to address the 1997 and 2008 Ozone National Ambient Air Quality Standards (NAAQS) require a present-day technical and economic feasibility analysis. If add-on control technology is evaluated in this manner and determined to be infeasible, other means of minimizing emissions are also evaluated. These other means include emission limitations and work practices.

   In the case of US Steel Clairton, although no new controls were identified, the RACT II evaluation determined through the examination of historical CEMS data for Boilers No. 1 and 2 and most recent stack test for Boilers No. R1, R2, T1 and T2 indicate that these boilers have emitted at a much lower NO_X emission rate than the RACT I emission limits established in 2001.

4. **Comment:** Both U.S. Steel's and ACHD's RACT reviews did not identify any technically or economically feasible control technology options for the six Clairton Boilers. Unilaterally lowering NO_X emission limits without the basis of a technologically and economically feasible control technology, is inappropriate. The lowering of NO_X emissions limit is not a "control technology". ACHD's analysis used average past actual emissions data to develop the NO_X emissions limits and did not consider the units' full potential to emit under various operating scenarios. The boilers are capable of burning differing amounts of coke oven gas and natural gas. Because these fuels have differing emission rates and factors, the potential emissions from the boilers are dependent on the fuel being burned. The boilers are typically fueled by a specific mixture of coke oven gas and natural gas. However, the boilers can and have operated on increased amounts of natural gas. Using an annual average data set as a basis for a 30-day average limit will mask higher 30-day actual emissions averages by averaging with lower 30-day actual emissions averages. Potential emissions of all operating scenarios will not be accurately represented through a review of average past actual data, and thus, basing a RACT II limit on only a year's worth of historical actual NO_X emissions is not appropriate. (1 Commenter)

   Response: The Department partially agrees with the commenter. See response to Comments #1 and #3 above.

5. **Comment:** The Clairton RACT II permit contradicts Consent Order, RACT Order No. 234 that was agreed to by ACHD and U. S. Steel on December 30, 1996. ACHD and U. S. Steel agree that there are no technologically and economically feasible control options since then that would require revision of the determination reached in that Order. (1 Commenter)

   Response: Clean Air Act, upon promulgation of new ozone NAAQS, requires an evaluation or re-evaluation of RACT (depending on whether one had been performed previously). The RACT I order issued in 1996 was based on the available technological and economical feasible control options at the time, and after 20 years, the Department believes that technology has improved and warrant the re-evaluation of the RACT I Order, including emission control equipment, emissions limits reduction, combustion optimization and improvement to address the 1997 and 2008 Ozone National Ambient Air Quality Standards (NAAQS). See response to Comment #3 above.

6. **Comment:** Installation Permit, Page 20, Table V-A-1 on notes that the lbs/MMBtu emission limit is based on a 30-day rolling average, but this is not noted for the hourly emission limit (lb/hr). The basis for these limits should match, since they are based on each other. Preferably, U.S. Steel recommends removing the lb/hr limit, as it is duplicative in this case. Incorporating this change and that requested in comment #1 above, condition V.A.1.d should be revised to: "d. NO_X emissions from each Boilers No. 1 or 2 shall not exceed the limitations in Table V-A-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)" (1 Commenter)

TABLE V-A-1: NO_X Emission Limitations

Process	~~Maximum Heat Input Capa~~ ~~MMBtu/hr~~	Emission Limit** lbs/MMBtu	~~Hourly Emission Limit (lb/hr)~~	Annual Emission Limit (tons/year)*
Boiler 1	~~761~~	~~0.34~~ **0.54**	~~258.40~~	~~1,133.79~~ **1,740**
Boiler 2	~~481~~	~~0.34~~ **0.54**	~~163.54~~	~~716.31~~ **1,258**

*A year is defined as any consecutive 12-month period.

**Based on a 30-day rolling average limit of 0.34 lbs/MMBtu.

Response: The Department disagrees, and the limits remain the same as were determined in the RACT II analysis. However, the lbs/MMbtu limit has been revised, which also affected the lbs/hr and tons/yr limit and they are both based on 30-day rolling average.

7. **Comment:** On page 22, under Work Practice Standards, revise "Boiler No. Bl or B2" to "Boilers No. 1 or 2." (1 Commenter)

   Response: The Department made the requested change.

8. **Comment:** On page 23, the header should be "Boilers Rl and R2" instead of "Boilers R2 and R2." Also, the Facility ID should be "B005 & B006" instead of "B006 & B006." (1 Commenter)

   Response: The Department made the requested change.

9. **Comment:** In "TABLE V-B-1: NO_X Emission Limitations", please remove the column titled "Maximum Heat Input Capacity, MM Btu/hr". Heat input is not a NO_X emission limit and is duplicative. The boiler heat input is listed in V. B. (1 Commenter)

   Response: The Department made the requested change.

10. **Comment:** Table V-B-1 on page 23 shows a "**" note on the lbs/MM Btu emission limit header, but there is no corresponding note below the table. U.S. Steel believed this"**" should be removed from the emission limit header. Preferably, U. S. Steel recommends removing the lb/hr limit, as it is duplicative in this case. Incorporating this change and that requested in comment #7, on page 23, condition V.B.1.c should be revised to: "c. NO_X emissions from each Boilers No. R1 or R2 shall not exceed the limitations in Table V-B-1 below: {25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)" (1 Commenter)

TABLE V-B-1: NO_X Emission Limitations

Process	~~*Maximum Heat Input Capacity MMBtu/hr*~~	*Emission Limit** lbs/MMBtu*	~~*Hourly Emission Limit (lb/hr)*~~	*Annual Emission Limit (tons/year)**
Boiler R1	~~229~~	~~0.31~~ **0.54**	~~70.99~~	~~310.94~~ **525**
Boiler R2	~~229~~	~~0.31~~ **0.54**	~~70.99~~	~~310.94~~ **525**

*A year is defined as any consecutive 12-month period.

Response: The Department removed the double asterisks (**). However, the Department disagrees, and the limits remain the same as were determined in the RACT II analysis.

11. **Comment:** On page 23, remove Condition V.B.3 as this requirement is already a Condition in the current Title V Operating Permit #0052. (1 Commenter)

    Response: The Department made the requested change.

12. **Comment:** In "TABLE V-C-1: NO_X Emission Limitations", please remove the column titled "Maximum Heat Input Capacity, MM Btu/hr". Heat input is not a NO_X emission limit and is duplicative. The boiler heat input is listed in V. C. (1 Commenter)

    Response: The Department made the requested change.

13. **Comment:** Table V-C-1 on page 25 shows a "**" note on the lbs/MMBtu emission limit header, but there is no corresponding note below the table. U.S. Steel believed this"**" should be removed from the emission limit header. Preferably, U. S. Steel recommends removing the lb/hr limit, as it is duplicative in this case. Incorporating this change and that requested in comment #9, on page 25, condition V.C.1.c should be revised to: "c. NO_X emissions from each Boilers No. T1 or T2 shall not exceed the limitations in Table V-C-1 below: {25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)" (1 Commenter)

TABLE V-C-1: NO_X Emission Limitations

Process	~~*Maximum Heat Input Capacity MMBtu/hr*~~	*Emission Limit** lbs/MMBtu*	~~*Hourly Emission Limit (lb/hr)*~~	*Annual Emission Limit (tons/year)**
Boiler T1	~~*156*~~	~~*0.31*~~ ***0.54***	~~*40.36*~~	~~*211.02*~~ ***358***
Boiler T2	~~*156*~~	~~*0.31*~~ ***0.54***	~~*40.36*~~	~~*211.02*~~ ***358***

**A year is defined as any consecutive 12-month period.*

Response: The Department removed the double asterisk (**). However, the Department disagrees, and the limits remain the same as were determined in the RACT II analysis.

14. **Comment:** On page 26, remove Condition V.C.3 as this requirement is already a Condition in the current Title V Operating Permit #0052. (1 Commenter)

Response: The Department made the requested change.

15. **Comment:** On page 28, change citation from "No. 235" to "No. 234." (1 Commenter)

Response: The Department made the requested change.

16. **Comment:** On page 30, "EMISSIONS LIMITATIONS SUMMARY" should be revised to "VII. EMISSIONS SUMMARY" with the following note: [This section is provided for informational purposes only and is not intended to be an applicable requirement.) Subsequently, the header in Table Vll-1 should be revised to remove "Limit" and the combined NO_X tons per year must be changed based on the revised limits to the boilers, as described above. (1 Commenter)

Response: The Department cannot make the requested changes because the limit is part of the facility's requirements under Section V of the permit.

17. **Comment:** On page 1 of the TSD, under the Executive Summary, "blast furnace gas (BFG)" can be removed as it is not combusted at the Clairton Plant. (1 Commenter)

Response: The Department made the requested change.

18. **Comment:** On page 2 of the TSD, revise Table 1 based on Installation Permit comments above. (1 Commenter)

Table 1 Technologically and Economically Feasible Control Options Summary for NO_x

Unit ID	Emissions Unit	Financially Feasible Control Option	Current NOx PTE	RACT II Reduction	Revised NOx PTE
P001	Underfiring Battery 1	None	336.0	0	336.0
P002	Underfiring Battery 2	None	299.1	0	299.1
P003	Underfiring Battery 3	None	311.2	0	311.2
P007	Underfiring Battery 13	None	236.2	0	236.2
P008	Underfiring Battery 14	None	206	0	206
P009	Underfiring Battery 15	None	255.9	0	255.9
P010	Underfiring Battery 19	None	1,194.80	0	1,194.80
P011	Underfiring Battery 20	None	1,194.80	0	1,194.80
P012	Underfiring Battery B	None	767.7	0	767.7
P046	Underfiring Battery C	None	556.8	0	556.8
P019	Desulfurization Plant	None	3.68	0	3.68
B010	Ammonia Flare	None	47.1	0	47.2
B001	Boiler 1	~~Lower NO_x limit~~ **None**	1740	~~608.21~~ **0**	~~1,131.79~~ **1740**
B002	Boiler 2	~~Lower NO_x limit~~ **None**	1285	~~568.69~~ **0**	~~716.31~~ **1258**
B005	Boiler R1	~~Lower NO_x limit~~ **None**	525	~~214.06~~ **0**	~~310.94~~ **525**
B006	Boiler R2	~~Lower NO_x limit~~ **None**	525	~~214.06~~ **0**	~~310.94~~ **525**
B007	Boiler T1	~~Lower NO_x limit~~ **None**	358	~~146.18~~ **0**	~~211.82~~ **358**
B008	Boiler T2	~~Lower NO_x limit~~ **None**	358	~~146.18~~ **0**	~~211.82~~ **358**
Total			**10,200**	~~**1,897**~~ **0**	~~**8,303**~~ **10,200**

Response: The Department cannot make the requested changes. The permit limits remain as those that were determined during the RACT II analysis.

19. **Comment:** On page 3 of the TSD, in Section III, change the number of coke batteries from "9" to "10," the production from "10,000 tons of coke per day" to "13,000 tons of coke per day," the coal from "16,000 tons of coal" to "18,000 tons of coal," and the coke oven gas produced from "215 million cubic feet" to "225 million cubic feet." (1 Commenter)

    Response: The Department made the requested changes.

20. **Comment:** On Page 4 of the TSD, in the last row of Table 3, please remove "and 3" from Boiler Nos. 1,2. (1 Commenter)

    Response: The Department made the requested change.

21. **Comment:** On page 5 of the TSD, revise Table 4 based on Installation Permit comments above. (1 Commenter)

Table 4 Facility Sources Subject to NO_X Case-by- Case RACT II and Existing RACT I Limits

Source ID	Description	Rating	NO_X PTE	NO_X Limit (RACT I)	Proposed NO_X	NO_X Limit (RACT II)
B001	Boiler No. 1	760 MMBtu/hr	1,740	0.54 lbs/MMBtu	~~1,131.79~~ **1,740**	~~0.34 lbs/MMBt~~ **N/A**
B002	Boiler No. 2	481 MMBtu/hr	1,258	0.54 lbs/MMBtu	~~716.31~~ **1,258**	~~0.34 lbs/MMBt~~ **N/A**
B005	Boiler R1	229 MMBtu/hr	525	0.54 lbs/MMBtu	~~310.94~~ **525**	~~0.31 lbs/MMBtu~~ **N/A**
B006	Boiler R2	229 MMBtu/hr	525	0.54 lbs/MMBtu	~~310.94~~ **525**	~~0.31 lbs/MMBtu~~ **N/A**
B007	Boiler T1	156 MMBtu/hr	358	0.54 lbs/MMBtu	~~211.82~~ **358**	~~0.31 lbs/MMBtu~~ **N/A**
B008	Boiler T2	156 MMBtu/hr	358	0.54 lbs/MMBtu	~~211.82~~ **358**	~~0.31 lbs/MMBtu~~ **N/A**
P001	Underfiring Battery 1	517,935 tons/yr of coal	336.0	N/A	336.0	N/A
P002	Underfiring Battery 2	517,935 tons/yr of coal	299.1	N/A	299.1	N/A
P003	Underfiring Battery 3	517,935 tons/yr of coal	311.2	N/A	311.2	N/A
P007	Underfiring Battery 13	545,675 tons/yr of coal	236.2	N/A	236.2	N/A
P008	Underfiring Battery 14	545,675 tons/yr of coal	206	N/A	206	N/A
P009	Underfiring Battery 15	545,675 tons/yr of coal	255.9	N/A	255.9	N/A
P010	Underfiring Battery 19	1,002,290 tons/yr of coal	1,194.80	N/A	1,194.80	N/A
P011	Underfiring Battery 20	1,002,290 tons/yr of coal	1,194.80	N/A	1,194.80	N/A
P012	Underfiring Battery B	1,491,025 tons/yr of coal	767.7	N/A	767.7	N/A
P046	Underfiring Battery C	1,379,059 tons/yr of coal	556.8	N/A	556.8	N/A
P019	Desulfurization Plant	6,394,800 tons of coke	31.45	N/A	31.45	N/A
B010	Ammonia Flare	12.5 MMBtu/hour	19.03	N/A	19.03	N/A

Response: The Department did not make the change. The permit limits remain as those that were determined during the RACT II analysis. See response to Comments #1 and #3 above.

22. **Comment:** On page 7 of the TSD, section IV, add "Steel" between "U. S." and "Clairton." (1 Commenter)

Response: The Department made the requested change.

23. **Comment:** On page 10 of the TSD, please remove Table 7 based on the Installation Permit comments above. (1 Commenter)

Response: The Department did not make the change. The permit limits remain as those that were determined during the RACT II analysis. See response to Comment #3 above.

24. **Comment:** On page 11 of the TSD, revise the following RACT Summary Table 8 based on comments above. (1 Commenter)

Table 8	RACT II Emission Reduction Summary	
NO_X Potential Emissions (tpy)		
Current PTE	RACT Reduction	Revised PTE
10,200	~~1,897~~ 0	~~8302.6~~ 10,200

Response: The Department did not make the change. The permit limits remain as those that were determined during the RACT II analysis. See response to Comment #3 above.

25. **Comment:** EPA has previously SIP approved RACT I for US Steel Clairton in 2001 (40 CFR 52.2020 (c)(172)(i)(B)(5)). ACHD must clearly identify those RACT I units, cross-index them with the current units at US Steel Clairton and indicate which units have shutdown, been modified or remain. As required under the Clean Air Act §110(l), ACHD must provide an evaluation and comparison of the RACT II vs. RACT I requirements to ensure that all emission units covered under RACT I have been accounted for and that there is no backsliding. Please identify and track all RACT I emission units and indicate if these units have been shutdown, modified or had a name change. Further, if the RACT I requirements still apply, ACHD should clearly state this in their review memo and ensure that the redacted permit provided for the SIP revision includes those applicable RACT I provisions. (1 Commenter)

Response: The Table below shows a comparison of the previously SIP-approved RACT I NO_X emission limits for USS Clairton Boilers in 2001 (40 CFR 52.2020 (c)(172)(i)(B)(5)), and the proposed RACT II requirements. These NO_X RACT II emission limits supersede RACT I limit for the active boilers that remain on-site. As shown in the Table 1 below, the proposed NO_X emission rates for Boiler Nos. 1 & 2, and Boilers R1, R2, T1 AND T2 are more stringent than the RACT I limit. Therefore, no backsliding would occur.

The draft RACT II IP20 will implement the NO_X RACT II limits for each boiler. It also contains testing, monitoring, recordkeeping and reporting requirements for the NO_X RACT II limits, and supersedes all of the 1996 NO_X RACT I requirements. Upon approval of these emission limits, a complete Title V Operating Permit renewal will be issued to incorporate all the existing applicable requirements along with the updated RACT II provisions for each boiler.

Table 1: RACT I vs. RACT II NO_X Emission Limits

Unit Description	Equipment Status Since RACT I Order	RACT I NO_X Emission Limit (lb/MMBtu)	RACT II NO_X Emission Limit (lb/MMBtu)
Boiler No. 1	Active – Remains on site	0.54	0.34
Boiler No. 2	Active – Remains on site	0.54	0.34
Boiler No. 13	Shut Down	0.54	NA
Boiler No, 14	Shut Down	0.54	NA
Boiler R1	Active – Remains on site	0.54	0.31
Boiler R2	Active – Remains on site	0.54	0.31
Boiler T1	Active – Remains on site	0.54	0.31
Boiler T2	Active – Remains on site	0.54	0.31

26. **Comment:** Please describe the potential NO_X and VOC emissions from the quench towers, which are listed in Table 6 as subject to the presumptive RACT requirements at 25 Pa. Code §129.97. Section 129.97 does not include the regulation of sources such as quench towers. Please indicate whether these are RACT subject emission units seeking a case by case RACT determination. If ACHD is making a RACT II determination for the quench towers, the analysis must include a detailed technical and feasibility analysis of these emission sources. (1 commenter)

    Response: There are no RACT I NO_X or VOC numerical limits for all the sources listed in Table 6 of the Technical Support Document. However, RACT I required the facility to "install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices" which the Department will retain as a case by case RACT II with the citation 25 Pa Code 129.99. In addition, the batteries' compliance with NESHAP, Subpart CCCCC, will also reduce the emissions of NO_X and VOC. The facility quench towers are subject to work practice requirement 63.7295(b) and has been referenced in the RACT II IP. Table 6 has been revised from presumptive to case by case RACT II.

27. **Comment:** Please clarify the emission units seeking case by case RACT determinations. Please clarify whether case by case RACT is being sought for the following emission units, which do not appear in the RACT I approval but appear in the current RACT II evaluation: P046 (Underfiring Battery C), P019 (Desulfurization Plant) and B010 (Ammonia Flare). All NO_X emission units emitting greater than 5 tpy potential emissions and all VOC emission units emitting greater than 2.7 tpy potential emissions are expected to be evaluated for case by case RACT unless there are applicable presumptive RACT II emission requirements already in the PA SIP. There appears to be conflicting information in the ACHD review memo as to the applicability of the VOC and NO_X requirements (whether case by case or presumptive). Please clarify and check each RACT subject emission unit for applicability to the presumptive vs. case by case RACT requirements. Specifically, please check the use of Source ID P046 as it used to describe three different emission units: Battery C, Quench Tower C and the 7A Quench

Tower. For those where a case by case VOC or NO_X RACT determination is being sought, please provide the necessary technical and feasibility analysis to support your conclusions. (1 commenter)

Response: C battery (Source ID P046) was permitted in 2008 and it was not subject to RACT I. The battery is designed with a "PROven" (Pressure Regulated Oven) system which regulates pressure within each oven chamber where the collector main operates under a negative pressure during coking in order to significantly reduce emissions including NO_X and VOC emissions and it was considered BACT. The battery is also equipped with emergency flare, which is determined as BACT to reduce VOC emissions. Therefore, the PROven system and emergency flare are considered case by case RACT II for C battery and it has been included in the RACT II IP20. The Desulfurization Plant (P019), which is the same as the SCOT Plant Incinerator in RACT I order and Ammonia Flare B010 are subject to case by case 25 Pa Code 129.99 and it has been included in the RACT II IP 20, Section V.D. See Section IV of the Technical Support Document for addition information on C battery and Desulfurization Plant (Incinerator). Meanwhile ACHD determined that NO_X RACT for the Desulfurization Plant SCOT incinerator is the current requirements established by Clairton's Title V permit enhanced by annual tune-ups. More specifically, the flare shall be installed, maintained, and operated in accordance with manufacturer specifications, and good engineering and air pollution control practices for minimizing emissions.

28. **Comment:** Please clarify the NO_X RACT discussion pertaining to the Flares to indicate what flares are being discussed (i.e.., Source ID number) and provide additional detail and rationale regarding why controls are technically infeasible. (1 Commenter)

    Response: A more detailed discussion on flares was added to the TSD.

29. **Comment:** The draft RACT permit currently includes only Source IDs B001, B002, B005, B006, B007 and B008. If case by case RACT (VOC or NO_X) requirements are being established for any of the other emission units, these units and those requirements must be included in the permit, including the appropriate monitoring, testing and recordkeeping provisions. If the presumptive RACT requirements at 25 Pa. Code §129.97 apply to any of the emission units, that regulatory citation should be added to the permit but is not a requirement for the case by case RACT action. (1 Commenter)

    Response: The boilers from RACT I are subject to case-by case RACT II NO_X limit and the appropriate citation 25 Pa Code 129.99 has been cited in the permit. All other sources not subject to the RACT I NO_X or VOC limit have been included in the permit, section V.D with the appropriate case by case citation.

30. **Comment:** The documents describing the Nonattainment New Source Review (NNSR) analysis of the replacement of Batteries 7, 8, and 9 by Battery C in 2008 include a description of an integrated emission control system with the potential to reduce NO_X and VOC emissions from Battery C (compared with Batteries 7-9). This system appears to be a technically and economical feasible control technology that could control emissions from Coke Oven Gas (COG) combustion, pushing operations, and fugitive emissions. Please describe this emission control system in detail with regard to the reduction of VOC and/or NO_X emissions from Battery C and its related operations and include it as part of the RACT technical and economic feasibility analysis for Battery C. The technical and economic feasibility analysis of monitoring options, including a NO_X Continuous Emission Monitoring System, CEMs, should also be considered. Appropriate monitoring, testing and recordkeeping needs to be discussed as part of the RACT determination. (1 Commenter)

    Response: A more detailed discussion on Battery C emission controls was added to the TSD.

31. **Comment:** The ACHD review memo concludes that there are no technically and economically feasible control options for the control of VOC and NO_X emissions at the coke oven batteries. However, the review states that US Steel Clairton's procedures "optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air." Please include a more detailed discussion about this balance and the technical infeasibility of control options for the batteries and suggest some potential good operating and maintenance practices as part of the case by case RACT determination for the coke batteries. (1 Commenter)

    Response: The facility coke batteries are subject to NESHAP, Subpart L for coke oven batteries, NESHAP Subpart CCCCC, and the work practice requirements §63.7300 and §63.306. These conditions have been incorporated into the Title V operating permit. The condition has been referenced in the RACT IP.

32. **Comment:** Please include a more detailed discussion regarding the suggested good work practices for minimization of VOC emissions from the quench towers and the desulfurization plant. (1 Commenter)

    Response: The facility's quench tower is subject to NESHAP, Subpart CCCCC workpractice standard 63.7295(b) and has already been incorporated into the Title V. The NESHAP has been referenced in the RACT II IP20

33. **Comment:** The ACHD review memo states that the SCOT plant thermal oxidizer that currently controls the VOC emissions from the desulfurization plant is considered the most effective VOC control measure. For the current RACT II analysis, ACHD must still provide a technical and economic feasibility analysis of other possible control options as compared with the current SCOT plant thermal oxidizer. (1 Commenter) *(EPA end)*

    Response: A discussion on other control technologies was added to the TSD.

34. **Comment:** A numeric emission limit may qualify as RACT. ACHD has determined that RACT for the Facility's six boilers is lower emission limits for NO_X, based on data from the continuous emission monitoring systems ("CEMS") units on the boilers' stacks. The proposed emissions limits would reduce the Facility's potential to emit ozone-forming NO_X from 10,200 tons per year to 8302.6 tons per year, a reduction of 1,897 tons per year, or more than 18%. In contrast to the Pennsylvania Code, Article XXI does not expressly include "emission limits" in its definition of RACT. Nevertheless, numeric emission limits, such as the new NO_X limits proposed for the Facility's six boilers, may qualify as RACT.
    Response: The Department concur with the commenter last sentence. Please see response to Comments #1 and #3 above.

35. **Comment:** New emission limits for the facility boilers may qualify as RACT if they are "consistently achievable." The review memo for ACHD's RACT determination for the Facility states that the proposed NO_X emission limits for the Facility's six boilers are based on monitoring data from the CEMS units on the boilers' stacks, specifically from 2013 for Boilers 1 and 2, and from 2012 for Boilers R1, R2, T1, and T2. ACHD's review memo does not, but should, explain why the CEMS data for 2012 and 2013 that was used to establish the proposed emission limits for the Facility's six boilers represent operating results that are "consistently achievable." ACHD should provide such an explanation; it would help refute any assertion that the proposed NO_X emission limits do not represent RACT. (1 Commenter)

    Response: See response to Comments #1 and #3.

36. **Comment:** ACHD's RACT determination for the facility's six boilers must consider the necessity of obtaining emission reductions, the social and economic impact of such reductions, and the availability of other means for attaining and maintaining the NAAQS. It is not clear that ACHD considered all of the factors purportedly required by Article XXI's definition of "RACT" in making its RACT determination for the Facility's six boilers. Specifically, it does not appear that ACHD considered the necessity for obtaining emission reductions, the social impact of such reductions, the economic impact of reductions on any party other than the Facility's operator, or other means (if any) of attaining and maintaining the 2008 NAAQS for ozone. ACHD's RACT analysis for the Facility's six boilers should incorporate all the factors that Article XXI uses to define "RACT," and the RACT determination for the Facility's six boilers should be revised based on that re-analysis, if necessary. (1 Commenter)

    Response: Pursuant to 44 FR 53762; September 17, 1979, RACT is defined as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source. In addition, the facility has made all attempts to attain and maintain the 2008 NAAQS for ozone considering all available technological and economic feasibility. The NAAQS, as well as the presumptive RACT limits already incorporate those "social and economic" impacts on the community at large, as defined in Article XXI.

37. **Comment:** The Council Appreciates the Department's lowering the emissions limitations for the Boilers (B001, B002, B003, and B004) based on stack test results. (1 Commenter)

    Response: The Department concurs with the commenter.

38. **Comment:** The Department should provide more substantiation for the proposed emissions limitations for the boilers. The Department should provide more information regarding its calculations for the proposed emissions limitations for the boilers. According to the Department, the proposed emissions limitations for Boilers 1 and 2 are "based on the 2013 annual average CEM result." Review Memorandum, page 10. In contrast, the proposed emissions limitations for Boilers R1, R2, T1, and T2 are "based on the 2012 average stack test of boiler R1 and a 20% increase for variability." The Department does not provide the actual calculations. In addition, it is not clear what is meant by an "average stack test." Instead of following this recommendation, the Department used one boiler to develop emission rates for four boilers, and it used one annual average CEM result to develop emission rates for two boilers. The Department should review and discuss more data before setting emissions limitations for these boilers. (1 Commenter)

    Response: There is a detailed discussion on the development of the emission limitations for the boilers in section IV of the Technical Support Document (TSD). To summarize, each of the six boilers was limited to a NO_X short term emission rate of 0.54 lbs/MMBTU, based on the previous 1996 RACT Order I. A review of the installed CEMS data for Boilers 1 and 2 indicates that the boilers annual average NO_X emission rates are typically half or less of the permitted limits, indicating that the boilers are being operated effectively for the age, types and size of these boilers. Boilers No. R1 and R2, and T1 and T2 are identical units by design and size, and the most recent stack test for boilers R1, R2, T1 and T2 indicate that the NO_X emission rates ranges from 0.132 to 0.2 lbs/MMBtu, which is generally lower than emission rates commonly associated with packaged natural gas fired boilers that employ low NO_X burners.

    Therefore, Boilers No. 1 and 2 emission limitations are based on the maximum 30-day average CEM results between 2014-2019 (see response to comment #1), while Boilers No. R1, R2, T1 and T2 are

based on the 2012 average stack test result of boiler R1. "Average stack result" is the average of 3 1-hour stack test runs.

39. **Comment:** The Department should require computer modeling for the retrofit option for the boilers, and it should include the information generated in a revised analysis of economic feasibility for this RACT II determination. In the review memorandum, the Department noted that modeling by computer simulation could be performed to actually calculate emissions reductions. It does not appear that the Department has required such modeling. Absent such modeling, the RACT II analysis is not complete. (1 Commenter)

    Response: Modelling is not required because the Boiler/burner vendors claimed that they cannot guarantee the potential reduction that it could achieve through retrofitting, and whether it could actually produce lower emission rates than what the boiler is currently emitting. Besides, Burner manufactures/vendor have indicated (quoted) that replacement burners would not achieve a reduction in NO_X, based upon the actual emission rates that are currently being achieved for Boiler #2, R1, R2, T1 and T2.

40. **Comment:** The Department should require a Leak Detection and Repair (LDAR) Plan for fugitive emissions of VOCs from the Coke By-Product Recovery Plant. Despite the existence of a gas blanketing system, there is the potential for leaks that can and should be addressed through a Leak Detection and Repair (LDAR) program -- a common control in the organic chemical manufacturing and transport industries. If implemented appropriately, even a minimal LDAR program could result in additional reductions of fugitive emissions of VOCs, due to the size and complexity of this facility. The Department stated that this was technically feasible. See Attachment 2, ERG Technical Support Document, page 68 ("it is technically feasible to implement a LDAR program that covers the BPRP (By-Product Recovery Plant] equipment."). Without a discussion of a form of control that is ubiquitous in the industry, the RACT II analysis is not complete. (1 Commenter)

    Response: The facility is subject to Leak Detection and Repair (LDAR) under 40 CFR Part 61, Subpart V (for equipment leaks), which is referenced in this permit. The LDAR requirements of Subpart V are considered RACT for the emissions from equipment leaks. All the applicable Subpart V requirements have already been incorporated into the Title V Operating Permit.

41. **Comment:** For the reasons stated in Comment #40 above, the Department should require a facility wide LDAR plan for all piping in service of VOCs, and that plan should extend to the Desulfurization Plant and Control Rooms. Inspection of piping in connection with the Desulfurization Plant (as well as Control Rooms) is especially important given the catastrophic fire on December 24, 2019 that rendered that plant inoperable for over three months. According to a report in the press, this was caused by a ruptured pipe. A facility wide LDAR plan should include leak detection and repair as well as other maintenance best practices to avoid leaks and other hazards. (1 Commenter)

    Response: The Department would continue to work with the facility to ensure compliance with the permit requirements. See response to comment #40 above.

42. **Comment:** The Department should revise the proposed Installation Permit to include the RACT requirements in determinations made by the Department in 2016. In 2016, the Department made RACT determinations for a number of emissions units at the facility. See ERG Technical Support Document dated July 25, 2016. However, the Department does not include all those RACT requirements in the proposed installation permit. In addition, the Department does not include all of those RACT requirements in the Title V permit, which pre-dated the 2016 RACT determination. The Department

should revise the proposed installation permit to include all the requirements set forth in the 2016 RACT determination. (1 Commenter)

1. The Department made a determination that RACT for the underfiring of coke batteries B, 1, 2, 3, 13, 14, 15, 19, and 20 included an annual tune-up, among other things.
2. The Department made a determination that RACT for the desulfurization plant included an annual tune-up, among other things.
3. The Department made a determination that RACT for the emergency flares included a flare minimization plan, among other things.
4. The Department made a determination that RACT for Boiler 1 included an annual tune- up, among other things. In addition, ERG concluded that SCR was cost-effective at a cost of $6,000-$7,800. The Department should explain why it now implies that SCR is not a technically feasible control option, whereas the 2016 technical support document says that it is technically feasible.
5. The Department made a determination that RACT for Boiler 2 included an annual tune- up, among other things. In addition, the Department concluded that SCR was cost-effective at a cost of $5,400. The Department should explain why it now implies that SCR is not a technically feasible control option, whereas the 2016 technical support document says that it is technically feasible.
6. The Department made a determination that RACT for Boilers R1, R2, T1, T2 included an annual tune-up, among other things. For RI and R2, the Department concluded that SCR cost $5,400 per ton. For TI and T2, Department concluded that SCR cost $6,000 per ton. ERG stated that "ACHD has determined that SCR is an economically feasible control option for Boilers R1 and R2." However, ERG stated that "ACHD has determined that SCR is not an economically feasible control option for Boilers T1 and T2." The Department should explain why it now implies that SCR is not an economically feasible control option for Boilers R1 and R2, in light of its past statement in 2016. See Review Memorandum, pages 8-9.

Response: The 2016 ERG analysis cited by the commenter was one of the bases for this RACT II determination. The Department did not make any RACT determinations at that time, and used the ERG analysis, as well as the facility's own analysis, and any other available experience and information to make this RACT determination.

The coke oven batteries are subject to NESAHP, Subpart CCCCC for Coke Ovens and Subpart L for Coke Oven Batteries. These two NESHAPs contain monitoring and work practice standards that required the facility to develop a written operation and maintenance plan for the general operation and maintenance of all coke oven batteries in accordance with a specific guidance and procedure, which has been incorporated into the Title V Operating permit.

The Technical Support Document, Section IV has explained why SCR or SNCR is not feasible for controlling NO_X emissions from the boilers. The ERG analysis had based control option technical and economic feasibility on boilers firing natural gas. However, due to the facility's operation and the fact that the primary fuel is coke oven gas, the vendors indicated that guarantees could not be provided unless testing of the alternative gas was performed to see the result and also the potential formation of byproducts such as silanes could pose problem.

The Department has incorporated the flare minimization plan into the RACT permit.

List of Commenters

Name	Affiliation
Christopher W. Hardin Air Manager	U.S. Steel Environmental
Cynthia H. Stahl, PhD. Environmental Scientist	U.S. Environmental Protection Agency Region III
John K. Baillie Senior Attorney	Group Against Smog & Pollution
Joseph Otis Minott, Esq.	Clean Air Council
Christopher D. Ahlers, Esq.	Clean Air Council

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1811

Reasonable Available Control Technology INSTALLATION PERMIT

Issued To:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855	**ACHD Permit#:**	**0052-I020**
		Date of Issuance:	------
		Expiration Date:	(See Section III.12)

Issued By: _____
JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: _____
Hafeez Ajenifuja
Air Quality Engineer

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DATE	*SECTION(S)*

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I. CONTACT INFORMATION

Facility Location:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855
Permittee/Owner:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855
Permittee/Operator: **(if not Owner)**	Same as Owner
Responsible Official:	**Kurt Barshick**
Title:	General Manager
Company:	U. S. Steel Mon Valley Works
Address:	P.O. Box 878 Dravosburg, PA 15034
Telephone Number:	(412) 675-2600
Fax Number:	(412) 675-5407
Facility Contact:	**Jonelle Scheetz**
Title:	Environmental Control Engineer
Telephone Number:	(412) 233-1015
Fax Number:	(412) 233-1011
E-mail Address:	jsscheetz@uss.com

AGENCY ADDRESSES:

ACHD Contact:	**Chief Engineer** **Allegheny County Health Department** Air Quality Program 301 39th Street, Building #7 Pittsburgh, PA 15201-1811
EPA Contact:	**Enforcement Programs Section (3AP12)** **USEPA Region III** 1650 Arch Street Philadelphia, PA 19103-2029

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II. FACILITY DESCRIPTION

FACILITY DESCRIPTION

U. S. Steel Mon Valley Works Clairton Plant is the largest by-products coke plant in North America. The Clairton Plant operates 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, approximately 225 million cubic feet of coke oven gas are 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 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 35 tons of elemental sulfur, and 50 tons of anhydrous ammonia. The coke produced is used in the blast furnace operations in the production of molten iron for steel making.

INSTALLATION DESCRIPTION

This installation permit is for inclusion of physical and operational conditions for subject facility pursuant to Reasonable Available Control Technology (RACT II) in section 2105.06 of Article XXI. There are no new units being added to the facility as part of this permitting action.

TABLE II-1: Emission Unit Identification

I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
P001	Coke Battery No. 1	Pushing Emission Control (PEC) Baghouse (P050 - Serves Batteries 1, 2 & 3)	517,935 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S001
P002	Coke Battery No. 2	PEC Baghouse (P050 - Serves Batteries 1, 2 & 3)	517,935 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S002
P003	Coke Battery No. 3	PEC Baghouse (P050 - Serves Batteries 1, 2 & 3)	517,935 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S003
P007	Coke Battery No. 13	PEC Baghouse (P052 - Serves Batteries 13, 14 & 15)	545,675 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S007
P008	Coke Battery No. 14	PEC Baghouse (P052 - Serves Batteries 13, 14 & 15)	545,675 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S008

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I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
P009	Coke Battery No. 15	PEC Baghouse (P052 - Serves Batteries 13, 14 & 15)	545,675 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S009
P010	Coke Battery No. 19	PEC Baghouse (P053 - Serves Batteries 19 & 20)	1,002,290 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S010
P011	Coke Battery No. 20	PEC Baghouse (P053 - Serves Batteries 19 & 20)	1,002,290 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S011
P012	Coke Battery B	PEC Baghouse (P054)	1,491,025 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S012
P044	Coke Battery C	PROven® system, Pushing Emission Control Baghouse	1,379,059 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S014
P019	Desulfurization Plant	Afterburner	6,394,800 tons of coke per year	Coke oven tail gas	S023
P044	Light Oil Barge Loading	Vapor Recovery to Boiler	55,000,000 gallons per year	Light Oil, Tar, and Tar Distillates	NA
B001	Boiler No. 1 (Babcock & Wilcox)	NA	760 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B002	Boiler No. 2 (Combustion Engineering)	NA	481 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B005	R1 Boiler (Riley Stoker)	NA	229 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B006	R2 Boiler (Riley Stoker)	NA	229 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B007	T1 Boiler (Erie City Zurn)	NA	156 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B008	T2 Boiler (Erie City Zurn)	NA	156 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B010	Ammonia Flare	NA	12.5 MMBtu/hour	Propane (assist gas)	NA

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DECLARATION OF POLICY

Pollution prevention is recognized as the preferred strategy (over pollution control) for reducing risk to air resources. Accordingly, pollution prevention measures should be integrated into air pollution control programs wherever possible, and the adoption by sources of cost-effective compliance strategies, incorporating pollution prevention, is encouraged. The Department will give expedited consideration to any permit modification request based on pollution prevention principles.

The permittee is subject to the terms and conditions set forth below. These terms and conditions constitute provisions of *Allegheny County Health Department Rules and Regulations, Article XXI Air Pollution Control*. The subject equipment has been conditionally approved for operation. The equipment shall be operated in conformity with the plans, specifications, conditions, and instructions which are part of your application, and may be periodically inspected for compliance by the Department. In the event that the terms and conditions of this permit or the applicable provisions of Article XXI conflict with the application for this permit, these terms and conditions and the applicable provisions of Article XXI shall prevail. Additionally, nothing in this permit relieves the permittee from the obligation to comply with all applicable Federal, State and Local laws and regulations.

III. GENERAL CONDITIONS

1. Prohibition of Air Pollution (§2101.11)

It shall be a violation of this permit to fail to comply with, or to cause or assist in the violation of, any requirement of this permit, or any order or permit issued pursuant to authority granted by Article XXI. The permittee shall not willfully, negligently, or through the failure to provide and operate necessary control equipment or to take necessary precautions, operate any source of air contaminants in such manner that emissions from such source:

a. Exceed the amounts permitted by this permit or by any order or permit issued pursuant to Article XXI;
b. Cause an exceedance of the ambient air quality standards established by Article XXI §2101.10; or
c. May reasonably be anticipated to endanger the public health, safety, or welfare.

2. Nuisances (§2101.13)

Any violation of any requirement of this Permit shall constitute a nuisance.

3. Definitions (§2101.20)

a. Except as specifically provided in this permit, terms used retain the meaning accorded them under the applicable provisions and requirements of Article XXI or the applicable federal or state regulation. Whenever used in this permit, or in any action taken pursuant to this permit, the words and phrases shall have the meanings stated, unless the context clearly indicates otherwise.

b. Unless specified otherwise in this permit or in the applicable regulation, the term "*year*" shall mean any twelve (12) consecutive months.

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4. Certification (§2102.01)

Any report or compliance certification submitted under this permit shall contain written certification by a responsible official as to truth, accuracy, and completeness. This certification and any other certification required under this permit shall be signed by a responsible official of the source, and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or Article XXI, and all equivalent compliance techniques that have been approved by the Department, shall be properly installed, maintained, and operated consistent with good air pollution control practice.

6. Conditions (§2102.03.c)

It shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02, for any person to fail to comply with any terms or conditions set forth in this permit.

7. Transfers (§2102.03.e)

This permit shall not be transferable from one person to another, except in accordance with Article XXI §2102.03.e and in cases of change-in-ownership which are documented to the satisfaction of the Department, and shall be valid only for the specific sources and equipment for which this permit was issued. The transfer of permits in the case of change-in-ownership may be made consistent with the administrative permit amendment procedure of Article XXI §2103.14.b.

8. Effect (§2102.03.g)

Issuance of this permit shall not in any manner relieve any person of the duty to fully comply with the requirements of Article XXI or any other provision of law, nor shall it in any manner preclude or affect the right of the Department to initiate any enforcement action whatsoever for violations of Article XXI or this Permit, whether occurring before or after the issuance of such permit. Further, the issuance of this permit shall not be a defense to any nuisance action, nor shall such permit be construed as a certificate of compliance with the requirements of Article XXI or this Permit.

9. General Requirements (§2102.04.a)

It shall be a violation of this Permit giving rise to the remedies set forth in Article XXI §2109 for any person to install, modify, replace, reconstruct, or reactivate any source or air pollution control equipment to which this Permit applies unless either:

a. The Department has first issued an Installation Permit for such source or equipment; or

b. Such action is solely a reactivation of a source with a current Operating Permit, which is approved under §2103.13 of Article XXI.

10. Conditions (§2102.04.e)

Further, the initiation of installation, modification, replacement, reconstruction, or reactivation under this

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Installation Permit and any reactivation plan shall be deemed acceptance by the source of all terms and conditions specified by the Department in this permit and plan.

11. Revocation (§2102.04.f)

a. The Department may, at any time, revoke this Installation Permit if it finds that:
   1. Any statement made in the permit application is not true, or that material information has not been disclosed in the application;
   2. The source is not being installed, modified, replaced, reconstructed, or reactivated in the manner indicated by this permit or applicable reactivation plan;
   3. Air contaminants will not be controlled to the degree indicated by this permit;
   4. Any term or condition of this permit has not been complied with;
   5. The Department has been denied lawful access to the premises or records, charts, instruments and the like as authorized by this Permit; or

b. Prior to the date on which construction of the proposed source has commenced the Department may, revoke this Installation Permit if a significantly better air pollution control technology has become available for such source, a more stringent regulation applicable to such source has been adopted, or any other change has occurred which requires a more stringent degree of control of air contaminants.

12. Term (§2102.04.g)

This Installation Permit shall expire in 18 months if construction has not commenced within such period or shall expire 18 months after such construction has been suspended, if construction is not resumed within such period. In any event, this Installation Permit shall expire upon completion of construction, except that this Installation Permit shall authorize temporary operation to facilitate shakedown of sources and air cleaning devices, to permit operations pending issuance of a related subsequent Operating Permit, or to permit the evaluation of the air contamination aspects of the source. Such temporary operation period shall be valid for a limited time, not to exceed 180 days, but may be extended for additional limited periods, each not to exceed 120 days, except that no temporary operation shall be authorized or extended which may circumvent the requirements of this Permit.

13. Annual Installation Permit Administrative Fee (§2102.10.c & e)

No later than 30 days after the date of issuance of this Installation Permit and on or before the last day of the month in which this permit was issued in each year thereafter, during the term of this permit until a subsequent corresponding Operating Permit or amended Operating Permit is properly applied for, the owner or operator of such source shall pay to the Department, in addition to all other applicable emission and administration fees, an Annual Installation Permit Administration Fee in an amount of $750.

14. Severability Requirement (§2103.12.l)

The provisions of this permit are severable, and if any provision of this permit is determined to by a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

15. Reporting Requirements (§2103.12.k)

a. The permittee shall submit reports of any required monitoring at least every six (6) months. All

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instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by the Responsible Official.

b. Prompt reporting of deviations from permit requirements is required, including those attributable to upset conditions as defined in this permit and Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

c. All reports submitted to the Department shall comply with the certification requirements of General Condition III.4 above.

d. Semiannual reports required by this permit shall be submitted to the Department as follows:
   1. One semiannual report is due by July 31 of each year for the time period beginning January 1 and ending June 30.
   2. One semiannual report is due by February 1 of each year for the time period beginning July 1 and ending December 31.
   3. The first semiannual report shall be due July 31, 2019 for the time period beginning on the issuance date of this permit through June 30, 2019.

e. Reports may be emailed to the Department at aqreports@alleghenycounty.us in lieu of mailing a hard copy.

16. Minor Installation Permit Modifications (§2102.10.d)

Modifications to this Installation Permit may be applied for but only upon submission of an application with a fee in the amount of $300 and where:

a. No reassessment of any control technology determination is required; and
b. No reassessment of any ambient air quality impact is required.

17. Violations (§2104.06)

The violation of any emission standard established by this Permit shall be a violation of this Permit giving rise to the remedies provided by Article §2109.02.

18. Other Requirements Not Affected (§2105.02)

Compliance with the requirements of this permit shall not in any manner relieve any person from the duty to fully comply with any other applicable federal, state, or county statute, rule, regulation, or the like, including, but not limited to, any applicable NSPSs, NESHAPs, MACTs, or Generally Achievable Control Technology standards now or hereafter established by the EPA, and any applicable requirement of BACT or LAER as provided by Article XXI, any condition contained in this Installation Permit and/or any additional or more stringent requirements contained in an order issued to such person pursuant to Part I of Article XXI.

19. Other Rights and Remedies Preserved (§2109.02.b)

Nothing in this permit shall be construed as impairing any right or remedy now existing or hereafter created in equity, common law or statutory law with respect to air pollution, nor shall any court be deprived of such jurisdiction for the reason that such air pollution constitutes a violation of this permit

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20. Penalties, Fines, and Interest (§2109.07.a)

A source that fails to pay any fee required under this Permit or article XXI when due shall pay a civil penalty of 50% of the fee amount, plus interest on the fee amount computed in accordance with of Article XXI §2109.06.a.4 from the date the fee was required to be paid. In addition, the source may have its permit revoked.

21. Appeals (§2109.10)

In accordance with State Law and County regulations and ordinances, any person aggrieved by an order or other final action of the Department issued pursuant to Article XXI shall have the right to appeal the action to the Director in accordance with the applicable County regulations and ordinances.

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IV. SITE LEVEL TERMS AND CONDITIONS

1. Reporting of Upset Conditions (§2103.12.k.2)

The permittee shall promptly report all deviations from permit requirements, including those attributable to upset conditions as defined in Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

2. Visible Emissions (§2104.01.a)

Except as provided for by Article XXI §2108.01.d pertaining to a cold start, no person shall operate, or allow to be operated, any source in such manner that the opacity of visible emissions from a flue or process fugitive emissions from such source, excluding uncombined water:

a. Equal or exceed an opacity of 20% for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or,
b. Equal or exceed an opacity of 60% at any time.

3. Odor Emissions (§2104.04) (County-only enforceable)

No person shall operate, or allow to be operated, any source in such manner that emissions of malodorous matter from such source are perceptible beyond the property line.

4. Materials Handling (§2104.05)

The permittee shall not conduct, or allow to be conducted, any materials handling operation in such manner that emissions from such operation are visible at or beyond the property line.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or any order under Article XXI, and all equivalent compliance techniques approved by the Department, shall be properly installed, maintained, and operated consistently with good air pollution control practice.

6. Open Burning (§2105.50)

No person shall conduct, or allow to be conducted, the open burning of any material, except where the Department has issued an Open Burning Permit to such person in accordance with Article XXI §2105.50 or where the open burning is conducted solely for the purpose of non-commercial preparation of food for human consumption, recreation, light, ornament, or provision of warmth for outside workers, and in a manner which contributes a negligible amount of air contaminants.

7. Shutdown of Control Equipment (§2108.01.b)

a. In the event any air pollution control equipment is shut down for reasons other than a breakdown, the person responsible for such equipment shall report, in writing, to the Department the intent to shut down such equipment at least 24 hours prior to the planned shutdown. Notwithstanding the submission of such report, the equipment shall not be shut down until the approval of the Department is obtained; provided, however, that no such report shall be required if the source(s) served by such air pollution control equipment is also shut down at all times that such equipment

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is shut down.

b. The Department shall act on all requested shutdowns as promptly as possible. If the Department does not take action on such requests within ten (10) calendar days of receipt of the notice, the request shall be deemed denied, and upon request, the owner or operator of the affected source shall have a right to appeal in accordance with the provisions of Article XI.

c. The prior report required by Site Level Condition IV.7.a above shall include:

1. Identification of the specific equipment to be shut down, its location and permit number (if permitted), together with an identification of the source(s) affected;
2. The reasons for the shutdown;
3. The expected length of time that the equipment will be out of service;
4. Identification of the nature and quantity of emissions likely to occur during the shutdown;
5. Measures, including extra labor and equipment, which will be taken to minimize the length of the shutdown, the amount of air contaminants emitted, or the ambient effects of the emissions;
6. Measures which will be taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impracticable to shut down or curtail the affected source(s) during the shutdown; and
7. Such other information as may be required by the Department.

8. Breakdowns (§2108.01.c)

a. In the event that any air pollution control equipment, process equipment, or other source of air contaminants breaks down in such manner as to have a substantial likelihood of causing the emission of air contaminants in violation of this permit, or of causing the emission into the open air of potentially toxic or hazardous materials, the person responsible for such equipment or source shall immediately, but in no event later than sixty (60) minutes after the commencement of the breakdown, notify the Department of such breakdown and shall, as expeditiously as possible but in no event later than seven (7) days after the original notification, provide written notice to the Department.

b. To the maximum extent possible, all oral and written notices required shall include all pertinent facts, including:

1. Identification of the specific equipment which has broken down, its location and permit number (if permitted), together with an identification of all related devices, equipment, and other sources which will be affected.
2. The nature and probable cause of the breakdown.
3. The expected length of time that the equipment will be inoperable or that the emissions will continue.
4. Identification of the specific material(s) which are being, or are likely to be emitted, together with a statement concerning its toxic qualities, including its qualities as an irritant, and its potential for causing illness, disability, or mortality.
5. The estimated quantity of each material being or likely to be emitted.
6. Measures, including extra labor and equipment, taken or to be taken to minimize the length of the breakdown, the amount of air contaminants emitted, or the ambient effects of the emissions, together with an implementation schedule.
7. Measures being taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impractical to shut down the source(s), or any part thereof, during the breakdown.

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c. Notices required shall be updated, in writing, as needed to advise the Department of changes in the information contained therein. In addition, any changes concerning potentially toxic or hazardous emissions shall be reported immediately. All additional information requested by the Department shall be submitted as expeditiously as practicable.

d. Unless otherwise directed by the Department, the Department shall be notified whenever the condition causing the breakdown is corrected or the equipment or other source is placed back in operation by no later than 9:00 AM on the next County business day. Within seven (7) days thereafter, written notice shall be submitted pursuant to Paragraphs a and b above.

e. Breakdown reporting shall not apply to breakdowns of air pollution control equipment which occur during the initial startup of said equipment, provided that emissions resulting from the breakdown are of the same nature and quantity as the emissions occurring prior to startup of the air pollution control equipment.

f. In no case shall the reporting of a breakdown prevent prosecution for any violation of this permit or Article XXI.

9. Cold Start (§2108.01.d)

In the event of a cold start on any fuel-burning or combustion equipment, except stationary internal combustion engines and combustion turbines used by utilities to meet peak load demands, the person responsible for such equipment shall report in writing to the Department the intent to perform such cold start at least 24 hours prior to the planned cold start. Such report shall identify the equipment and fuel(s) involved and shall include the expected time and duration of the startup. Upon written application from the person responsible for fuel-burning or combustion equipment which is routinely used to meet peak load demands and which is shown by experience not to be excessively emissive during a cold start, the Department may waive these requirements and may instead require periodic reports listing all cold starts which occurred during the report period. The Department shall make such waiver in writing, specifying such terms and conditions as are appropriate to achieve the purposes of Article XXI. Such waiver may be terminated by the Department at any time by written notice to the applicant.

10. Monitoring of Malodorous Matter Beyond Facility Boundaries (§2104.04)

The permittee shall take all reasonable action as may be necessary to prevent malodorous matter from becoming perceptible beyond facility boundaries. Further, the permittee shall perform such observations as may be deemed necessary along facility boundaries to insure that malodorous matter beyond the facility boundary in accordance with Article XXI §2107.13 is not perceptible and record all findings and corrective action measures taken.

11. Emissions Inventory Statements (§2108.01.e & g)

a. Emissions inventory statements in accordance with §2108.01.e shall be submitted to the Department by March 15 of each year for the preceding calendar year. The Department may require more frequent submittals if the Department determines that more frequent submissions are required by the EPA or that analysis of the data on a more frequent basis is necessary to implement the requirements of Article XXI or the Clean Air Act.

b. The failure to submit any report or update within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit

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giving rise to the remedies provided by Article XXI §2109.02.

12. Orders (§2108.01.f)

In addition to meeting the requirements Site Level Conditions IV.7 through IV.11, inclusive, the person responsible for any source shall, upon order by the Department, report to the Department such information as the Department may require in order to assess the actual and potential contribution of the source to air quality. The order shall specify a reasonable time in which to make such a report.

13. Violations (§2108.01.g)

The failure to submit any report or update thereof required by Site Level Conditions IV.7 through IV.12 above, inclusive, within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

14. Emissions Testing (§2108.02)

a. **Orders:** No later than 60 days after achieving full production or 120 days after startup, whichever is earlier, the permittee shall conduct, or cause to be conducted, such emissions tests as are specified by the Department to demonstrate compliance with the applicable requirements of this permit and shall submit the results of such tests to the Department in writing. Upon written application setting forth all information necessary to evaluate the application, the Department may, for good cause shown, extend the time for conducting such tests beyond 120 days after startup but shall not extend the time beyond 60 days after achieving full production. Emissions testing shall comply with all applicable requirements of Article XXI, §2108.02.e.

b. **Tests by the Department:** Notwithstanding any tests conducted pursuant to this permit, the Department or another entity designated by the Department may conduct emissions testing on any source or air pollution control equipment. At the request of the Department, the permittee shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.

c. **Testing Requirements:** No later than 45 days prior to conducting any tests required by this permit, the person responsible for the affected source shall submit for the Department's approval a written test protocol explaining the intended testing plan, including any deviations from standard testing procedures, the proposed operating conditions of the source during the test, calibration data for specific test equipment and a demonstration that the tests will be conducted under the direct supervision of persons qualified by training and experience satisfactory to the Department to conduct such tests. In addition, at least 30 days prior to conducting such tests, the person responsible shall notify the Department in writing of the time(s) and date(s) on which the tests will be conducted and shall allow Department personnel to observe such tests, record data, provide pre-weighed filters, analyze samples in a County laboratory and to take samples for independent analysis. Test results shall be comprehensively and accurately reported in the units of measurement specified by the applicable emission limitations of this permit.

d. Test methods and procedures shall conform to the applicable reference method set forth in this permit or Article XXI Part G, or where those methods are not applicable, to an alternative sampling and testing procedure approved by the Department consistent with Article XXI §2108.02.e.2.

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e. **Violations:** The failure to perform tests as required by this permit or an order of the Department, the failure to submit test results within the time specified, the knowing submission of false information, the willful failure to submit complete results, or the refusal to allow the Department, upon presentation of a search warrant, to conduct tests, shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

15. Abrasive Blasting (§2105.51)

a. Except where such blasting is a part of a process requiring an operating permit , no person shall conduct or allow to be conducted, abrasive blasting or power tool cleaning of any surface, structure, or part thereof, which has a total area greater than 1,000 square feet unless such abrasive blasting complies with all applicable requirements of Article XXI §2105.51.

b. In addition to complying with all applicable provisions of §2105.51, no person shall conduct, or allow to be conducted, abrasive blasting of any surface unless such abrasive blasting also complies with all other applicable requirements of Article XXI unless such requirements are specifically addressed by §2105.51.

16. Asbestos Abatement (§2105.62, §2105.63)

In the event of removal, encasement, or encapsulation of Asbestos-Containing Material (ACM) at a facility or in the event of the demolition of any facility, the permittee shall comply with all applicable provisions of Article XXI §2105.62 and §2105.63.

17. Volatile Organic Compound Storage Tanks (§2105.12.a)

No person shall place or store, or allow to be placed or stored, a volatile organic compound having a vapor pressure of 1.5 psia or greater under actual storage conditions in any aboveground stationary storage tank having a capacity equal to or greater than 2,000 gallons but less than or equal to 40,000 gallons, unless there is in operation on such tank pressure relief valves which are set to release at the higher of 0.7 psig of pressure or 0.3 psig of vacuum or at the highest possible pressure and vacuum in accordance with State or local fire codes, National Fire Prevention Association guidelines, or other national consensus standard approved in writing by the Department. Petroleum liquid storage vessels that are used to store produced crude oil and condensate prior to lease custody transfer are exempt from these requirements.

18. Permit Source Premises (§2105.40)

a. **General.** No person shall operate, or allow to be operated, any source for which a permit is required by Article XXI Part C in such manner that emissions from any open land, roadway, haul road, yard, or other premises located upon the source or from any material being transported within such source or from any source-owned access road, haul road, or parking lot over five (5) parking spaces:

1. Are visible at or beyond the property line of such source;

2. Have an opacity of 20% or more for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or

3. Have an opacity of 60% or more at any time.

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b. **Deposition on Other Premises:** Visible emissions from any solid or liquid material that has been deposited by any means from a source onto any other premises shall be considered emissions from such source within the meaning of Site Level Condition IV.18.a above.

19. Parking Lots and Roadways (§2105.42)

a. The permittee shall not maintain for use, or allow to be used, any parking lot over 50 parking spaces or used by more than 50 vehicles in any day or any other roadway carrying more than 100 vehicles in any day or 15 vehicles in any hour in such manner that emissions from such parking lot or roadway:

1. Are visible at or beyond the property line;

2. Have an opacity of 20% or more for a period or periods aggregating more than three (3) minutes in any 60 minute period; or

3. Have an opacity of 60% or more at any time.

b. Visible emissions from any solid or liquid material that has been deposited by any means from a parking lot or roadway onto any other premises shall be considered emissions from such parking lot or roadway.

c. Site Level Condition IV.19.a above shall apply during any repairs or maintenance done to such parking lot or roadway.

d. Notwithstanding any other provision of this permit, the prohibitions of Site Level Condition IV.19 may be enforced by any municipal or local government unit having jurisdiction over the place where such parking lots or roadways are located. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violations of Site Level Condition IV.19.

20. Permit Source Transport (§2105.43)

a. No person shall transport, or allow to be transported, any solid or liquid material outside the boundary line of any source for which a permit is required by Article XXI Part C in such manner that there is any visible emission, leak, spill, or other escape of such material during transport.

b. Notwithstanding any other provision of this permit, the prohibitions of Site Level Condition IV.20 may be enforced by any municipal or local government unit having jurisdiction over the place where such visible emission, leak, spill, or other escape of material during transport occurs. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violation of Site Level Condition IV.20.

21. Construction and Land Clearing (§2105.45)

a. No person shall conduct, or allow to be conducted, any construction or land clearing activities in such manner that the opacity of emissions from such activities:

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1. Equal or exceed 20% for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or
2. Equal or exceed 60% at any time.

b. Notwithstanding any other provision of this permit, the prohibitions of Site Level Condition IV.21 may be enforced by any municipal or local government unit having jurisdiction over the place where such construction or land clearing activities occur. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violations of Site Level Condition IV.21.

22. Mining (§2105.46)

No person shall conduct, or allow to be conducted, any mining activities in such manner that emissions from such activities:

a. Are visible at or beyond the property line;
b. Have an opacity of 20% or more for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or,
c. Have an opacity of 60% or more at any time.

23. Demolition (§2105.47)

a. No person shall conduct, or allow to be conducted, any demolition activities in such manner that the opacity of the emissions from such activities equal or exceed 20% for a period or periods aggregating more than three (3) minutes in any 60 minute period.

b. Notwithstanding any other provisions of this permit, the prohibitions of Site Level Condition IV.23 may be enforced by any municipal or local government unit having jurisdiction over the place where such demolition activities occur. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violations of Site Level Condition IV.23.

24. Fugitive Emissions (§2105.49)

The person responsible for a source of fugitive emissions, in addition to complying with all other applicable provisions of this permit shall take all reasonable actions to prevent fugitive air contaminants from becoming airborne. Such actions may include, but are not limited to:

a. The use of asphalt, oil, water, or suitable chemicals for dust control;
b. The paving and maintenance of roadways, parking lots and the like;
c. The prompt removal of earth or other material which has been deposited by leaks from transport, erosion or other means;
d. The adoption of work or other practices to minimize emissions;
e. Enclosure of the source; and
f. The proper hooding, venting, and collection of fugitive emissions.

25. Episode Plans (§2106.02)

The permittee shall upon written request of the Department, submit a source curtailment plan, consistent

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with good industrial practice and safe operating procedures, designed to reduce emissions of air contaminants during air pollution episodes. Such plans shall meet the requirements of Article XXI §2106.02.

26. New Source Performance Standards (§2105.05)

a. It shall be a violation of this permit giving rise to the remedies provided by §2109.02 of Article XXI for any person to operate, or allow to be operated, any source in a manner that does not comply with all requirements of any applicable NSPS now or hereafter established by the EPA, except if such person has obtained from EPA a waiver pursuant to Section 111 or Section 129 of the Clean Air Act or is otherwise lawfully temporarily relieved of the duty to comply with such requirements.

b. Any person who operates, or allows to be operated, any source subject to any NSPS shall conduct, or cause to be conducted, such tests, measurements, monitoring and the like as is required by such standard. All notices, reports, test results and the like as are required by such standard shall be submitted to the Department in the manner and time specified by such standard. All information, data and the like which is required to be maintained by such standard shall be made available to the Department upon request for inspection and copying.

27. National Emission Standards for Hazardous Air Pollutants (§2104.08)

a. The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.*

28. Facility-wide Emission Limitations

On or before 90 days after the initial startup and commissioning of the new Cogeneration units, the permittee shall permanently shutdown the three (3) existing Boiler No. 1, Boiler No. 2 and Boiler R1. [§2102.04.b.6]

29. The permittee shall not operate, or allow to be operated, any source in such manner that unburned coke oven gas is emitted into the open air. In addition, the permittee shall not flare, mix, or combust coke oven gas, or allow such gas to be flared, mixed or combusted unless the concentration of sulfur compounds, measured as hydrogen sulfide, in such gas is less than or equal to 35 grains per hundred dry standard cubic feet of coke oven gas produced by Clairton Plant, when all sulfur emissions from the Claus Sulfur Recovery Plant and the tail gas cleaning equipment thereon, expressed as equivalent H_2S are added to the measured H_2S. The concentration of sulfur compounds specified shall include the tail-gas sulfur, measured as hydrogen sulfide, emitted from sulfur removal equipment. [§2105.21.h].

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V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Boilers No. 1 & 2:

Process Description: Steam Production
Facility ID: B001 & B002
Capacity: 760 MMBtu/hr; 481 MMBtu/hr
Raw Materials: Desulfurized coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. 1or 2, shall not at any time exceed 0.34 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. The NOx emissions in conditions V.A.1.c shall be determined by a thirty (30) day rolling average and a twelve (12) month rolling average Continuous Emission Monitoring (CEM) data for the lbs/MMBtu and tons/yr emission limitation respectively. (25 Pa Code §129.99; RACT Order No. 234, Condition 1.5; 2102.04.b.5; §2105.06.d)

d. NO_X emissions from each Boilers No. 1 or 2 shall not exceed the limitations in Table V-A-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-A-1: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 1	761	0.34	258.40	1,133.79
Boiler 2	481	0.34	163.54	716.31

*A year is defined as any consecutive 12-month period.
**Based on a 30-day rolling average limit of 0.34 lbs/MMBtu.

2. Testing Requirements:

a. Emissions of NO_X may be determined by the CEMs required in Condition V.A.3 below in lieu of a stack test to determine compliance with the emissions limitation of Condition V.A.1.b and V.A.1.d above. (§2103.12.i; §2103.12.h.1; §2108.02; §2108.03; 25 Pa Code §129.100)

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 and §2108.02. (§2103.12.h.1)

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3. Monitoring Requirements:

a. The permittee shall install, operate, and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with 25 PA Code §§139.101 - 139.111 relating to requirements for continuous in-stack monitoring for stationary sources. (§2108.03.b.2 and RACT Plan 234)

4. Record Keeping Requirements:

a. The permittee shall maintain all appropriate records to demonstrate compliance with the requirements of §2105.06. Such records shall provide sufficient data and calculations to clearly demonstrate that all requirements of §2105.06 are met. The permittee shall record and maintain such data and information required to determine compliance for the facility in a time frame consistent with the averaging period of the requirements of both §2105.06 and RACT Order No. 235. Such information shall include, but not be limited to, the following minimum information which shall be submitted to the Department as a written report at three month intervals: (§2102.04.b.5; §2108.03.d, §2105.06; 25 Pa Code §129.100; RACT Plan 234)

1. All recording and reporting required by Section 2108.03 of Article XXI and entitled "Continuous Emission Monitoring."
2. An identification of each instance during the reporting period during which emissions exceeded the applicable emission limitation rates in Condition V.A.1.b above and an identification of the reasons, if known, for such exceedance. The averaging period used for making such identification shall correspond to the averaging period specified in condition V.A.1.d above.
3. An identification of each period during which the continuous emission monitoring system was inoperative, except for zero and span drift checks, the reasons therefore, and the nature of repairs or adjustments performed or to be performed.
4. An identification of calibrations, zero and span drift checks, and other quality assurance procedures.

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2; RACT Plan 234, Condition 1.8)

5. Reporting Requirements:

a. The permittee shall report the following information semi-annually to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. The reports shall be postmarked by the 30th day following the end of the reporting period. (§2103.12.k; §2103.12.a.2.D)

1. Total monthly Fuel Combustion Unit, fuel use, per fuel type;
2. Cold start information; and
3. Non-compliance information required to be recorded by Condition V.A.4.b above

b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)

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6. Work Practice Standards:

At no time shall the permittee allow Boiler No. B1 or B2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

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B. Boilers R2 and R2: B005 & B006

Process Description: Steam production
Facility ID: B006 & B006
Max. Design Rate: 229 MMBtu/hr, each (Heat Input)
Capacity: 229 MMBtu/hr, each (Heat Input)
Raw Materials: Desulfurized coke oven gas
Control Device: NA

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. 1or 2, shall not at any time exceed 0.31 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. NO_X emissions from each Boilers No. R1 or R2 shall not exceed the limitations in Table V-B-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-B-1: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler R1	229	0.31	70.99	310.94
Boiler R2	229	0.31	70.99	310.94

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform emissions testing on Boilers R1 and R2 at least once every two years for NO_X. Such testing shall be in accordance with EPA Methods 7 through 7E or other such methods as approved by the Department. [RACT Plan 234 and §2108.02.c; §2107.05]

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 above and Article XXI §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

The volume of coke oven gas combusted in Boiler R2 and the H_2S content of the coke oven gas shall be monitored and recorded on a daily basis (midnight to midnight). (§2103.12.i)

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4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: (§2103.12.j; 25 Pa Code §129.100)

1. Records of the amount of coke oven gas combusted and the H_2S content of the coke oven gas (daily, monthly and 12 months)
2. Cold starts (date, time and duration of each occurrence);
3. Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2)

5. Reporting Requirements:

a. The permittee shall report the following information semi-annually to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. (§2103.12.k; §2103.12.a.2.D)

1. Monthly and 12-month data required to be recorded by Condition V.B.4.a above;
2. Cold start information; and
3. Non-compliance information required to be recorded by Condition V.B.4.b above

b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)

6. Work Practice Standards:

At no time shall the permittee allow Boiler No. R1 or R2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

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C. Boilers T1 and T2: Existing Boiler T1 & T2

Process Description: Steam production
Facility ID: B007 & B008
Max. Design Rate: 156 MMBtu/hr, each (Heat Input)
Capacity: 156 MMBtu/hr, each (Heat Input)
Raw Materials: Desulfurized coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. T1or T2, shall not at any time exceed 0.31 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. NO_X emissions from each Boilers No. T1 or T2 shall not exceed the limitations in Table V-C-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-C-1: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler T1	156	0.31	40.36	211.02
Boiler T2	156	0.31	40.36	211.02

*A year is defined as any consecutive 12-month period.

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2. Testing Requirements:

a. The permittee shall perform emissions testing on Boilers T1 and T2 at least once every two years for NO_X. Such testing shall be in accordance with EPA Methods 7 through 7E or other such methods as approved by the Department. (RACT Plan 234 and §2108.02.c; §2107.05)

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 above and Article XXI §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

The volume of coke oven gas and natural gas combusted in Boilers T1 and T2 and the H_2S content of the coke oven gas shall be monitored and recorded on a daily basis (midnight to midnight). (§2103.12.i)

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers T1 and T2: (§2103.12.j; 25 Pa Code §129.100)

1. Records of the type and amount of fuel combusted and the H_2S content of the coke oven gas (daily, monthly and 12 months)
2. Cold starts (date, time and duration of each occurrence);
3. Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2)

5. Reporting Requirements:

a. The permittee shall report the following information to the Department semi-annually in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. The reports shall be postmarked by the 30th day following the end of the reporting period. (§2103.12.k; §2103.12.a.2.D)

1. Monthly and 12-month data required to be recorded by Condition V.C.4.a above;
2. Cold start information; and
3. Non-compliance information required to be recorded by Condition V.C.4.b above

b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)

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6. Work Practice Standards:

At no time shall the permittee allow Boiler No. T1 or T2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

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D. Process Equipment Sources

a. At no time shall the permittee operate the following equipment at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 235, Condition 1.1; 25 Pa Code §129.99; §2102.04.b.5)

1. Coke Oven Batteries No. 1, 2, 3, 13,1 4, 15, 19, 20, B and C
2. Pushing Emission Control System for the batteries specified in V.D.a.1
3. Desulfurization Plant
4. Scot Plant Incinerator
5. Wastewater Treatment Plant

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VI. ALTERNATIVE OPERATING SCENARIOS

There are no alternative operating scenarios for this operation.

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VII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the annual maximum potential RACT II NO_X emissions for Boilers B1, B2, R1, R2, T1 and T2.

TABLE VII-1: Emission Limitations Summary

Pollutant	Annual Combined Emission Limit (tons/year)*
Nitrogen Oxides (NO_X)	2,092.94

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ALLEGHENY COUNTY HEALTH DEPARTMENT
AIR QUALITY PROGRAM

February 10, 2020

SUBJECT: **Reasonable Available Control Technology (RACT II) Determination**
U.S. Steel Clairton Plant
400 State Street
Clairton, PA 15025-1855
Allegheny County

Installation Permit No. 0052-I020

TO: JoAnn Truchan, P.E.
Section Chief, Engineering

FROM: Hafeez Ajenifuja
Air Quality Engineer

I. Executive Summary

U.S. Steel Clairton Plant is defined as a major source of NO_X and VOC emissions and was subjected to a Reasonable Achievable Control Technology (RACT II) review by the Allegheny County Health Department (ACHD) required for the 1997 and 2008 Ozone National Ambient Air Quality Standard (NAAQS). The findings of the review established that technically and financially feasible RACT would result in the following emissions changes, summarized below.

The PA proposed presumptive RACT does not specify emission rates for combustion units that fire coke oven gas (COG), blast furnace gas (BFG), or fuel blends.

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Table 1 Technically and Financially Feasible Control Options Summary for NO_X

Unit ID	Emissions Unit	Financially Feasible Control Option	Current NO_X PTE	RACT II Reduction	Revised NO_X PTE
P001	Underfiring Battery 1	None	336.0	0	336.0
P002	Underfiring Battery 2	None	299.1	0	299.1
P003	Underfiring Battery 3	None	311.2	0	311.2
P007	Underfiring Battery 13	None	236.2	0	236.2
P008	Underfiring Battery 14	None	206	0	206
P009	Underfiring Battery 15	None	255.9	0	255.9
P010	Underfiring Battery 19	None	1,194.80	0	1,194.80
P011	Underfiring Battery 20	None	1,194.80	0	1,194.80
P012	Underfiring Battery B	None	767.7	0	767.7
P046	Underfiring Battery C	None	556.8	0	556.8
P019	Desulfurization Plant	None	3.68	0	3.68
B010	Ammonia Flare	None	47.1	0	47.2
B001	Boiler 1	Lower NO_X limit	1740	608.21	1,131.79
B002	Boiler 2	Lower NO_X limit	1285	568.69	716.31
B005	Boiler R1	Lower NO_X limit	525	214.06	310.94
B006	Boiler R2	Lower NO_X limit	525	214.06	310.94
B007	Boiler T1	Lower NO_X limit	358	146.18	211.82
B008	Boiler T2	Lower NO_X limit	358	146.18	211.82
Total			**10,200**	**1,897**	**8,303**

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Table 2 Technically and Financially Feasible Control Options Summary for VOC

Unit ID	Emissions Unit	Financially Feasible Control Option	Current VOC PTE	RACT II Reduction	Revised VOC PTE
P001	Underfiring Battery 1	None	4.8	0	4.8
P002	Underfiring Battery 2	None	4.4	0	4.4
P003	Underfiring Battery 3	None	3.8	0	3.8
P007	Underfiring Battery 13	None	3.4	0	3.4
P008	Underfiring Battery 14	None	3.3	0	3.3
P009	Underfiring Battery 15	None	3	0	3
P010	Underfiring Battery 19	None	10.4	0	10.4
P011	Underfiring Battery 20	None	10.4	0	10.4
P012	Underfiring Battery B	None	11	0	11
P046	Underfiring Battery C	None	7.8	0	7.8
P019	Desulfurization Plant	None	4.34	0	4.34
B010	Ammonia Flare	None	0.49	0	0.49
P021	Coke Byproduct Recovery Plant	None	58.0	0	58.0
P044	Light Oil Barge Loading	None	0.75	0	0.75
B001	Boiler 1	None	18.31	0	18.31
B002	Boiler 2	None	11.59	0	11.59
B005	Boiler R1	None	5.52	0	5.52
B006	Boiler R2	None	5.52	0	5.52
B007	Boiler T1	None	3.76	0	3.76
B008	Boiler T2	None	3.76	0	3.76
Total			**174.4**	0	**174.4**

II. Regulatory Basis

ACHD requested all major sources of NO_X (potential emissions of 100 tons per year or greater) and all major sources of VOC (potential emissions of 50 tons per year or greater) to reevaluate NO_X and/or VOC RACT for incorporation into Allegheny County's portion of the PA SIP. The U.S. Steel Clairton Plant requested a case by case RACT II determination under 25 Pa Code 129.99 for units P001, P002, P003, P007, P008, P009, P010, P021, P044 B001, B002 and B005, B006, B007, B008. This document is the result of ACHD's determination of RACT for these emission sources based on the materials submitted by the subject source and other relevant information.

III. Facility Description, Existing RACT I, Sources of NO_X, and Sources of VOC

U.S. Steel Clairton Works is the largest by-products coke plant in North America. Clairton Works operates 9 coke batteries and produces approximately 10,000 tons of coke per day from the destructive distillation (carbonization) of more than 16,000 tons of coal. During the carbonization process, approximately 215 million cubic feet of coke oven gas are 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 includes 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 35 tons of elemental sulfur, and 50 tons of anhydrous ammonia. There are six (6) Boilers at Clairton, which are used to generate steam, heat, and electricity for the plant. The two (2) primary fuels for the boilers are Coke Oven Gas, (COG), and Natural Gas (NG). On December 30th, 1996 the facility entered into a consent decree with the Department to meet RACT I obligations under RACT Order No. 234. RACT Order 234 was approved as RACT by EPA in 2001 (66 FR 52511). The RACT I requirements are listed in Table 3 below:

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Table 3 RACT I Summary

Source	RACT Order 234 Condition No.	RACT I Requirement
Coke Batteries No. 1,2,3,13,14,15,19,20, B and Battery C; Pushing Emission Control System for the batteries; Boilers 1,2, R1, R2, T1 and T2; By-Products Plant Coke Oven Gas Blanketing System and all process units blanketing by this system; Scot Plant Incinerator; and Wastewater Treatment Plant	I.1.1	At no time shall USX operate the following equipment at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices, with the exception of actions to mitigate emergency conditions.
Boiler Nos. 1, 2, R1, R2, T1 and T2	I.1.2	Boiler 1 NO_X limits: 0.54 MMBtu, 1,740 tons/yr; Boiler 2 NO_X limits: 0.54 MMBtu, 1,285 tons/yr; Boiler R1 NO_X limits: 0.54 MMBtu, 525 tons/yr; Boiler R2 NO_X limits: 0.54 MMBtu, 525 tons/yr; Boiler T1 NO_X limits: 0.54 MMBtu, 358 tons/yr; Boiler T2 NO_X limits: 0.54 MMBtu, 358 tons/yr;
Boiler Nos. R1, R2, T1 and T2	I.1.3	Boilers shall perform NO_X emissions stack test every two (2) years to determine compliance with NOx limit in lb/MMBtu
Boiler Nos. 1 and 2	I.1.4	Boilers shall use CEMS.
Boiler Nos. 1 and 2	I.1.5	Compliance with NO_X limits determine by 30-day rolling average for lbs/MMBtu and 12-month rolling average for tons/yr limits.
By-Products Plants	I.1.6	Properly maintain and operate the clean coke oven gas blanketing system at all times. Incinerate all VOC emissions processed by the blanketing system in the coke batteries or boilers.
Boiler Nos. 1, 2 and 3	I.1.7; I.1.8	The permittee shall retain and maintain all appropriate records to demonstrate compliance with the requirements of both Section 2105.06 of Article XXI and this Order.

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Case-by-Case RACT II and Existing RACT I Limits

Table 4 Facility Sources Subject to NO_X Case-by- Case RACT II and Existing RACT I Limits

Source ID	Description	Rating	NO_X PTE (TPY)	NO_X Limit (RACT I)	Proposed NO_X PTE	NO_X Limit (RACT II)
B001	Boiler No. 1	760 MMBtu/hr	1,740	0.54 lbs/MMBtu	1,131.79	0.34 lbs/MMBtu
B002	Boiler No. 2	481 MMBtu/hr	1,258	0.54 lbs/MMBtu	716.31	0.34 lbs/MMBtu
B005	Boiler R1	229 MMBtu/hr	525	0.54 lbs/MMBtu	310.94	0.31lbs/MMBtu
B006	Boiler R2	229 MMBtu/hr	525	0.54 lbs/MMBtu	310.94	0.31lbs/MMBtu
B007	Boiler T1	156 MMBtu/hr	358	0.54 lbs/MMBtu	211.82	0.31lbs/MMBtu
B008	Boiler T2	156 MMBtu/hr	358	0.54 lbs/MMBtu	211.82	0.31lbs/MMBtu
P001	Underfiring Battery 1	517,935 tons/yr of coal	336.0	N/A	336.0	N/A
P002	Underfiring Battery 2	517,935 tons/yr of coal	299.1	N/A	299.1	N/A
P003	Underfiring Battery 3	517,935 tons/yr of coal	311.2	N/A	311.2	N/A
P007	Underfiring Battery 13	545,675 tons/yr of coal	236.2	N/A	236.2	N/A
P008	Underfiring Battery 14	545,675 tons/yr of coal	206	N/A	206	N/A
P009	Underfiring Battery 15	545,675 tons/yr of coal	255.9	N/A	255.9	N/A
P010	Underfiring Battery 19	1,002,290 tons/yr of coal	1,194.80	N/A	1,194.80	N/A
P011	Underfiring Battery 20	1,002,290 tons/yr of coal	1,194.80	N/A	1,194.80	N/A
P012	Underfiring Battery B	1,491,025 tons/yr of coal	767.7	N/A	767.7	N/A
P046	Underfiring Battery C	1,379,059 tons/yr of coal	556.8	N/A	556.8	N/A
P019	Desulfurization Plant	6,394,800 tons of coke	31.45	N/A	31.45	N/A
B010	Ammonia Flare	12.5 MMBtu/hour	19.03	N/A	19.03	N/A

Table 5 Facility Sources Subject to VOC Case-by-Case RACT II and Existing RACT I Limits

Source ID	Description	Rating	VOC PTE (TPY)	VOC Limit (RACT I)	Proposed VOC PTE	VOC Limit (RACT II)
B001	Boiler No. 1	760 MMBtu/hr	18.31	N/A	18.31	N/A
B002	Boiler No. 2	481 MMBtu/hr	11.59	N/A	11.59	N/A
B005	Boiler R1	229 MMBtu/hr	5.52	N/A	5.52	N/A
B006	Boiler R1	229 MMBtu/hr	5.52	N/A	5.52	N/A
B007	Boiler T1	156 MMBtu/hr	3.76	N/A	3.76	N/A
B008	Boiler R1	156 MMBtu/hr	3.76	N/A	3.76	N/A
P001	Underfiring Battery 1	517,935 tons/yr of coal	4.8	N/A	4.8	N/A
P002	Underfiring Battery 2	517,935 tons/yr of coal	4.4	N/A	4.4	N/A
P003	Underfiring Battery 3	517,935 tons/yr of coal	3.8	N/A	3.8	N/A
P007	Underfiring Battery 13	545,675 tons/yr of coal	3.4	N/A	3.4	N/A
P008	Underfiring Battery 14	545,675 tons/yr of coal	3.3	N/A	3.3	N/A
P009	Underfiring Battery 15	545,675 tons/yr of coal	3	N/A	3	N/A
P010	Underfiring Battery 19	1,002,290 tons/yr of coal	10.4	N/A	10.4	N/A
P011	Underfiring Battery 20	1,002,290 tons/yr of coal	10.4	N/A	10.4	N/A
P012	Underfiring Battery B	1,491,025 tons/yr of coal	11	N/A	11	N/A
P046	Underfiring Battery C	1,379,059 tons/yr of coal	7.8	N/A	7.8	N/A
P019	Desulfurization Plant	6,394,800 tons of coke	4.34	N/A	4.34	N/A

Presumptive RACT II per PA Code 129.97

Table 6	Facility Sources Subject to the Presumptive RACT II per PA Code 129.97				
Source ID	**Description**	**Rating**	**NO_X PTE (TPY)**	**VOC PTE (TPY)**	**Presumptive RACT Requirement (**25 Pa Code Section 129.97)
P001	Underfiring Battery 1	517,935 tons/yr of coal	336.0	4.8	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P002	Underfiring Battery 2	517,935 tons/yr of coal	299.1	4.4	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P003	Underfiring Battery 3	517,935 tons/yr of coal	311.2	3.8	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P007	Underfiring Battery 13	545,675 tons/yr of coal	236.2	3.4	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P008	Underfiring Battery 14	545,675 tons/yr of coal	206	3.3	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P009	Underfiring Battery 15	545,675 tons/yr of coal	255.9	3	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P0010	Underfiring Battery 19	1,002,290 tons/yr of coal	1,194.80	10.4	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P011	Underfiring Battery 20	1,002,290 tons/yr of coal	1,194.80	10.4	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P012	Underfiring Battery B	1,491,025 tons/yr of coal	767.7	11	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P046	Underfiring Battery C	1,379,059 tons/yr of coal	767.7	7.8	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
	Pushing Emission for the batteries				Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P044	Light Oil Barge Loading	55,000,000 gallons/yr	NA	8.74	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P019	Desulfuriza-tion Plant	6,394,800 tons of coke	3.68	4.34	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
B010	Ammonia Flare	None	47.1	0.49	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P013	Quench Tower No. 1	1,553,805 tons/yr of coal	1.55	9.71	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P015	Quench Tower No. 5	1,637,025 tons/yr of coal	1.88	9.17	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P016	Quench Tower No. 7	2,004,580 tons/yr of coal	1.70	13.83	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P017	Quench Tower B	1,491,025 tons/yr of coal	2.89	9.83	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P046	Quench Tower C	1,379,059 tons/yr of coal	2.77	11.07	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P051	5A Quench Tower	1,270,200 tons/yr of coal	1.88	10.80	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices
P046	7A Quench Tower	1,555,630 tons/yr of coal	1.70	13.22	Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices

IV. RACT Determination

Two detailed RACT Reviews were performed to evaluate the U.S. Clairton facility; one was performed by U.S. Steel Clairton Plant, and one by Allegheny County Health Department (ACHD). Both submissions were considered in the final RACT disposition for the Facility and findings from each were incorporated into the ACHD RACT II Determination.

COKE BATTERY UNDERFIRE COMBUSTION STACKS (P001-B003; P007-P012)

Based on review of the referenced documents, literature available from vendors, engineering judgment and experience, the following NO_X control options were identified as potentially technically feasible for the batteries at U.S Steel Clairton facility:

1. LNB / ULNB -No, these are direct fired heating systems.
2. FGR -No, 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.
3. RSCR -No, not proven on coke batteries and rerouting would be too extensive.
4. SNCR-Yes, with preheating of the exhaust gas.
5. SCR - No, due to large potential outlet temperature and volumetric flowrate changes.

Coke batteries are operated at a relatively high excess air level compared to some other combustion processes. Excess air in coke ovens is needed to maintain compliance with other battery stack emissions regulations, namely the Article XXI and NESHAPs requirements. A source of emissions from battery stacks is coke oven gas leakage from the oven chambers into the combustion flues. This leakage typically occurs at local sites where imperfection in the oven walls exist allowing some leakage. Excess air allows the leaking gas to be efficiently burned instead of being emitted from the stack as particulate matter or VOC. Clairton Works' procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. In this balance, minimizing excess air is important as a fuel conservation method. Also, 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. Additionally, operation with sufficient excess air is needed to assure complete combustion of the COG that can be subject to heating value variability.

Pollution prevention/combustion modifications - LNB, FGR, are not technically feasible control options for Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20. The underfiring process, by virtue of its design, is ill-suited for retrofit emission reductions techniques for the following reasons:

- While other combustion processes (e.g. that of a boiler) can be highly tuned (via changes to over- and under-fire air, air-to-fuel ratios, exhaust recirculation etc.) to reduce emissions or accommodate changes in back pressure (created by add-on pollution control), a coke battery's underfiring system cannot. While the principle of all coke ovens is the same, each coke oven and oven operation is unique due to wide variations in the geometry of the combustion chambers, the combustion variables of fuel and air mixtures, temperature, humidity, and other factors.

- With burners and heating/exhaust flues distributed throughout the battery oven walls and infrastructure, an entire battery would need to be dismantled and rebuilt to accommodate modifications to the underfiring system. Even if such an endeavor was completed, there is little information available regarding the effectiveness of the NO_X control that would be achieved.

- The underfiring process has a very large volumetric exhaust flow rate (approximately 56,000-102,000 dscf/min) and relies on certain flame temperatures and flame lengths to adequately produce coke products.

Modifications to the underfiring system are likely to compromise requisite flame, air flow characteristics, system backpressure, and the quality of the coke produced.

- Clairton's standard operating procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. In doing so, the existing combustion optimization process functions as a fuel conservation method.

- Staged combustion for a coke battery underfiring process has been successfully designed and utilized by Battery C. However, that battery was originally designed with the pollution prevention technology and permitted for construction in 2008.

- It is not possible to reduce the temperature of the preheated combustion air or the fuel. All of the batteries are constructed of refractory brick, and the regenerators are beneath the ovens and heating flues and are an integral part of the structure. Fuel passing through the gun-flues in Batteries 1-3, 13-15 and B or the risers in Batteries 19 and 20 is heated by the surrounding ovens, heating flues and regenerators. Revising the path of the fuel gas or combustion air to the burners would require complete reconstruction of the battery.

Add-on Pollution Controls (SCR and SNCR)

SCR: Clairton's coke battery combustion and exhaust system does not operate with exhaust gas temperatures and airflows in the range where SCR can be effectively utilized. The average flue gas temperature of the combustion stack is approximately 493 °F; between 100 and 300 degrees cooler than what would be needed to ensure effective operation of an SCR. Because of the massive exhaust airflow, preheating the exhaust would require additional fuel combustion that would significantly offset the emissions reductions achieved by the SCR.

According to literature research and discussions with vendors, it was determined that regenerative SCR (RSCR) has primarily been utilized to control NO_X from relatively small biomass-fired boilers. There is no evidence that RSCR has been applied to a coke battery underfiring system. In addition, the retroactive installation of a post-combustion NO_X control, like SCR, would likely increase back pressure on the system and cause combustion process control to become erratic. This kind of process upset would likely result in increased emissions, poor coke quality and potentially compromise the integrity of the battery and the Clairton's ability to operate it safely. As a result, SCR is not technically feasible.

SNCR: There are no known applications, demonstrated or commercially operational, of SNCR to a coke oven battery underfiring/combustion system. 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. As a result, SNCR is not technically feasible.

<u>BOILERS</u>

The six facility boilers were reviewed for potential control of NO_X emissions, in accordance with the applicable control technologies. Boiler 1 is a cyclone type rated at 760 MM BTU/hr heat input, boiler 2 is four-wall-fired rated at 480 MMBTU/hr, and R1, R2, T1 and T2 are packaged wall-fired units (R1 and R2 are each rated at 229 MMBTU/hr, and T1 and T2 are each rated at 156 MMBTU/hr). Boilers number R1 and R2, and T1 and T2 are identical units by design and size, therefore only one boiler of each set was reviewed (since the results for the

identical boiler would be the same). The operational difference amongst the boilers is potential variation in steam output that is required on a yearly basis. Boilers #1 and 2 operate continuously throughout the year to provide the primary steam demands; they are typically only shutdown for annual outages (maintenance). Based on normal operations steam demands, on a yearly average basis Boilers 1 and 2, is between approximately 50-75% of rated load. Boiler 1 is normally operated at a base-load (consistent supply rate) with Boiler 2 operating in the swing-load mode (remainder of the load requirements at any given time). When either Boiler 1 or 2 are down, the four remaining boilers (R1, R2, T1 and T2) are operated to provide the required steam demands. The steam production capability for combination of the four boilers (R1, R2, T1 and T2} is approximately equivalent to the steam capability of Boiler #1. An Annual outage are planned during periods of lower steam demand (e.g. summer} so that during annual outages less steam is required throughout the plant; typically, boilers R1, R2 and T1 operate near rated load and T2 is operated as a swing load. Annual outages occur for a duration of approximately 14 to 30 days per year. However, if an unexpected outage of either Boiler #1 or 2 occurs, the remaining four boilers will be operated to supplement the steam demand. In light of this, actual annual emissions from the four boilers are significantly lower than their potential annual emissions. This flexibility, to operate any of boilers R1, R2, T1 and T2 on an unlimited basis at any given time, is necessary to assure that sufficient steam supply will always be available (in case of an unexpected extensive or permanent shutdown of Boilers #1 or 2).

Each of the six boilers is limited to a NO_X short term emission rate of 0.54 lbs/MMBTU, based on the previous 1996 RACT Order I. Continuous Emission Monitors (CEMS) have been installed on Boilers 1 and 2 for NO_X and 0_2 monitoring. A review of CEMS data for Boilers 1 and 2 indicates that the boilers annual average NO_X emission rates are typically half or less of the permitted limits, indicating that the boilers are being operated effectively for the age, types and size of these boilers. The most recent stack test for boilers R1, R2, T1 and T2 indicate that the NO_X emission rates ranges from 0.132 to 0.2 lbs/MMBTU. All test results are based on firing COG, the primary fuel. It is assumed that emission rates would be approximately equivalent while firing natural gas. These NO_X emission rates for boilers R1, R2, T1 and T2 are generally lower than emission rates commonly associated with packaged natural gas fired boilers that employ low NOx burners. Burner manufactures have indicated (quoted) that replacement burners would not achieve a reduction in NO_X, based upon the actual emission rates that are currently being achieved, for Boiler #2, R1, R2, T1 and T2. Boiler 1 is currently operating at or below burner manufacturer's indicated rates during ozone season. Additionally, due to the low excess air already being achieved, FGR or additional OFA will not be feasible; further suppression of excess air by these means would likely terminate the flame or pilot (which has been seen in cases like this before). Greater reduction in excess air would also lead to incomplete combustion, resulting in an increase in VOC and opacity emissions. In a retrofit situation, the boiler design (i.e., windbox, FD/ID fans, damper positions, burner locations, etc.) would have to be modeled by computer simulation to identify the NO_X emission rates that can be achieved through retrofitting, and whether it could actually produce lower emission rates. Boiler/burner vendors would not quote potential emission reduction for such changes due to these issues. Therefore, pre-combustion controls were not reviewed further for Boilers #2, R1, R2, T1 and T2.

Addition of SCR or SNCR can reduce NO_X emissions. SCR is expected to be capable of reducing NO_X emissions by 80% and SNCR by 45%. However, vendors indicated that guarantees could not be provided until testing of the alternative gas was completed, due to the potential formation of byproducts such as silanes. Nonetheless a cost effectiveness analysis was performed on one representative boiler based upon the referenced NO_X reduction efficiency versus the annual potential emissions of 1,740 tons/yr. The exhaust gas streams will also have to be pre-heated before they are directed to the SCR or SNCR units, since the exhaust gases are generally less than 400°F. Results for this analysis will be the same as for the other boilers.

Meanwhile, the PA proposed presumptive RACT does not specify emission rates for combustion units that fire COG or fuel blends and as enumerated above, the boilers annual average NO_X emission rates are typically half or less of the permitted RACT I limits. Consequently, the Department has determined the following to be RACT II limits for the six boilers:

Table 7

Boiler	Lbs/MMBtu	Tons/yr
No. 1	0.34	1,131.79
No. 2	0.34	716.31
R1	0.31	310.94
R2	0.31	310.94
T1	0.31	211.82
T2	0.31	211.82

This conclusion for boilers 1 & 2 is based on the 2013 annual average CEM result while boilers R1, R2, T1 and T2 are based on the 2012 average stack test of boiler R1 and a 20% increase for variability. The quarterly CEM monitoring and bi-annual stack testing required by the facility's Title V operating permit conditions shall be used to comply with the proposed RACT II limit.

DESULFURIZATION PLANT (INCINERATOR):

1. LNB / ULNB - No, the incinerator burner nozzles, oxygen and fuel feed, and combustion chambers are already inherently designed for NO_X control; no changes to these units are available without impact on emission reduction performance of other pollutants (which could cause a violation of the performance requirements).
2. FGR -No, the incinerator is a regenerative type unit. As such, it already employs flue gas recirculation as part of the system design. The incinerator is not designed to handle any additional volumetric flow.
3. RSCR - No, RSCR has not been proven on incineration units. No vendor guarantees would be provided.
4. SNCR-Yes, with preheating of the incinerator exhaust gas.
5. SCR- Yes, with supplemental heat reduction of the incinerator exhaust gas.

NO_X emissions are produced from the waste gas incineration process. As previously indicated, the incinerator is a regenerative type unit, and no pre-combustion controls are available that would affect NO_X emission rate. However, the incinerator gas exhaust can be treated with SCR or SNCR. SCR application would require the pre-absorption of heat since the incinerator exhaust can range from 1,500 to 2,000°F. The exhaust gas would have to be lowered to a rate of at least 1,200°F to enable the use of the high temperature catalyst. A heat exchanger would need to be installed to add heat (as needed} to the exhaust gas for application of SNCR, as the gas inlet must be above at least 1,600°F.

Tail gas from the desulfurization unit is exhausted to the SCOT Plant thermal oxidizer. Thermal oxidation is considered to be the most effective means of reducing VOCs. Since the emissions are already controlled by incineration, no addition controls were reviewed.

FLARES

The flares at Clairton Works operate on an emergency basis only and burner packages and FGR that limit NO_X are not amenable to such flares; add-on controls cannot be used on flares.

BY -PRODUCTS PLANT

As indicated in the previous RACT analysis, the by-products plant emissions are controlled by the gas blanketing system, which controls over 98% of the VOCs. The gas blanketing system is considered to be RACT for this source. The Light Oil Barge Loading facility is presently 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

DRAFT

V. RACT Summary

The RACT II conditions are at least as stringent as those from RACT I. Other RACT I conditions not affected by RACT II remain in effect. Based on the findings in this RACT analysis, the U.S. Steel Clairton Plant emissions can be summarized as follows:

Table 8 RACT II Emission Reduction Summary		
NO_X Potential Emissions (tpy)		
Current PTE	**RACT Reduction**	**Revised PTE**
10,200	**1,897**	**8302.6**
VOC Potential Emissions (tpy)		
Current PTE	**RACT Reduction**	**Revised PTE**
174.4	0	**174.4**

As shown in Table 8, the new RACT II conditions reduce 1,897 tons per year of potential NO_X emissions and 0 tons per year of potential VOC emissions from the U.S. Steel Clairton facility.

DRAFT

VI. RACT II Permit Conditions

Table 9

Source ID	Description	Permit Condition 0051-I020	RACT II Regulations
B001-B002	Boilers 1 and 3	Condition V.A.1.b Condition V.A.1.c Condition V.A.1.d Condition V.A.2.a Condition V.A.2.b Condition V.A.3.a Condition V.A.4.a Condition V.A.4.c Condition V.A.6.a	25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.100 25 PA Code §129.99
B005-B006	Boilers R1 and R2	Condition V.B.1.b Condition V.B.1.c Condition V.A.4.a Condition V.A.4.c Condition V.A.6.a	25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.100 25 PA Code §129.100
B007 & B008	Boilers T1 and T2	Condition V.C.1.b Condition V.C.1.c Condition V.C.4.a Condition V.C4.c Condition V.C.6.a	25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.99 25 PA Code §129.100 25 PA Code §129.100
P001-P003	Coke Oven Batteries 1-3	Condition V.D	25 PA Code §129.99
P004-P006	Coke Oven Batteries 14-16	Condition V.C	25 PA Code §129.99
P010-P011	Coke Oven Batteries 19 and 20	Condition V.C	25 PA Code §129.99
P012	Coke Oven Battery B	Condition V.C	25 PA Code §129.99
P019	Desulfurization Plant (SCOT Plan)	Condition V.C	25 PA Code §129.99
P021	Coke By-Product Recovery Plant	Condition V.C	25 PA Code §129.99
P046	Coke Oven Battery C	Condition V.C	25 PA Code §129.99

Allegheny County Health Department

Technical Support Document (TSD) - REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) DETERMINATION

July 25, 2016

Source Information

Source Name:	United States Steel Corporation - Mon Valley Works Clairton Plant
Source Location:	400 State Street, Clairton, PA 15025-1855
Mailing Address:	400 State Street, Clairton, PA 15025-1855
County:	Allegheny
SIC Code:	3312
Part 70 Permit No.:	0052
Major Source:	NOx and VOC
Permit Reviewer:	ERG/BS

The Allegheny County Health Department (ACHD) has performed the following RACT analyses for United States Steel Corporation - Mon Valley Works, Clairton Plant ("Clairton") relating to its by-product recovery coke plant and ancillary operations.

Background

Allegheny County was designated marginal nonattainment for the 2008 8-hour ozone on April 30, 2012 (published in 77 FR 30160, May 21, 2012). In order to implement the 2008 NAAQS for ozone, EPA issued a proposed rulemaking in June 2013 to provide steps and standards for states to develop and submit certain materials, dependent on each state's attainment status. Although Allegheny County is designated marginal nonattainment, Pennsylvania is also a part of the Ozone Transport Region (OTR), which must meet more stringent requirements, including submitting a RACT SIP (State Implementation Plan) for EPA approval. As such, Allegheny County must re-evaluate the NOx and VOC RACT in the existing RACT SIP for the eight-hour ozone NAAQS.

ACHD requested all major sources of NOx (potential emissions of 100 tons per year or greater) and all major sources of VOC (potential emissions of 50 tons per year or greater) to reevaluate NOx and/or VOC RACT for incorporation into Allegheny County's portion of the PA SIP. This document is the result of ACHD's review of the RACT re-evaluations submitted by the subject source and supplemented with additional information as needed by ACHD.

RACT Summary

NOx and VOC RACT evaluations were conducted for several emission units at Clairton. A summary of the corresponding RACT determinations is presented in the following tables:

Table 1. NOx RACT Findings for Clairton[a]

Unit/Operation	RACT determination	NOx Potential To Emit (ton/yr)	
		Before RACT	After RACT
Underfiring from Batteries 1-3, 13-15, 19, 20, B	Lower Permit Limits Based on Records; Annual Tune-ups	5,628	3,513[b]
Desulfurization Plant	Annual Tune-ups, continued operation as permitted	31.5	4.60[c]
Emergency Flares	Continued operation as permitted	19.03[d]	19.03
Boiler 1	Annual tune-up and continue to meet permit conditions	1,740	1,740
Boiler 2	Installation of SCR, annual tune-up, and continue to meet permit conditions	1,285	133
Boilers R1 and R2 (each)	Installation of SCR, annual tune-up, and continue to meet permit conditions	525	54
Boilers T1 and T2 (each)[e]	Annual tune-up and continue to meet permit conditions	358	358

[a] LNB/ULNB at lower permit limits may also be an option. LNB/ULNB at existing permit limits results in a performance no better than that received from CEMS and stack testing. (By Doug Oleniacz)
[b] No reduction in PTE for permit since these reductions are based on tune-ups-(By Doug Oleniacz)
[c] Uses information from November 2015 stack testing. See RACT Section A of this TSD for further information. (By Doug Oleniacz)
[d] TVOP Page 253-(By Doug Oleniacz)
[e]See RACT analysis for an explanation (Bob Sidner)

Table 2. VOC RACT Findings for Clairton

Unit/Operation	RACT determination	VOC Potential To Emit (ton/yr)	
		Before RACT	After RACT
Underfiring from Batteries 1-3, 13-15, 19, 20, B	Continued operation as permitted	314[a]	314
By-Products Recovery Plant	Clean COG gas-blanketing system and LDAR program	124	2.4
Desulfurization Plant	Incineration as permitted	398	5.78[b]

[a]Worksheet "Table A-4a Underfire Stacks" of X:\Public Health Programs\Air Quality\AQ Common\AQ Documents\u\us steel clairton\permits\operating permits\draft\clairton - tvcalcs – draft.xlsx: 28 + 28 + 28 + 29.5 + 29.5 + 29.5 + 54.2 + 54.2 + 80.6 = 361.4 tpy (PTE from 2014 US Steel Clairton RACT submittal is 314.3 tpy.)

[b]See RACT analysis for an explanation [Bob Sidner)

Note that the proposed PA presumptive RACT, as currently written, does not address the COG emission units covered by these RACT evaluations/determinations. Even though several of these combustion units use natural gas as a backup fuel, the natural gas usage is much less than the COG usage[1]. Since the natural gas usage is so low relative to the COG usage, the PA Presumptive RACT limits for natural gas usage were not included in this RACT.

[1][2009-2014 emissions inventory records show natural gas usage is less than 10% of the COG usage].

RACT Evaluations

RACT is "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." (44 FR 53761, 9/17/1979)

ACHD provided the following guidance to the major sources of NOx and VOC in Allegheny County for performing the RACT analyses:

1. The analysis shall address all reasonably possible controls of VOCs and NOx including changes in operation and work practices.

2. All control technology that is found to be technically infeasible must be accompanied by detailed and documented reason(s) as to why the technology is not feasible. General statements about the non-applicability of control technology to your industry will not be sufficient.

3. All changes in operation and work practices that are found not to be feasible require the same documentation as the controls in step #2 above.

4. All feasible control technology, changes in operation, work practices, etc. that are found to be cost prohibitive require a cost analysis demonstrating the cost per ton of pollutant controlled.

5. The analysis shall be done according to the procedures in EPA's OAQPS Cost Manual, EPA's cost spreadsheets are recommended where applicable.[1]

6. All data used in cost estimates, such as exhaust flow rates or the amount of ductwork used need proper documentation. If vendor quotes are used in the analysis for equipment costs, they are required to be supplied. Old analyses increased for inflation will not be acceptable. VATAVUK Air Pollution Control Cost Indexes shall be used with the aforementioned cost spreadsheets.

Each RACT analysis section is organized by the following 4 steps, which incorporate the guidance elements provided by Allegheny:

Step 1 – Identify Control Options (guidance element 1)
Step 2 – Eliminate Technically Infeasible Control Options (guidance elements 2 and 3)
Step 3 – Evaluate Control Options, including costs and emission reductions (guidance elements 4, 5, and 6)
Step 4 – Select RACT (guidance element 1)

[1] Available at: http://www.epa.gov/ttnecas1/costmodels.html

Source/Process Description

Clairton is the largest by-products coke plant in North America. It operates 9 coke batteries and produces (daily) approximately 10,000 tons of coke and 215 million cubic feet of coke oven gas (COG) from the destructive distillation (carbonization) of more than 16,000 tons of coal. The volatile products contained in the COG are recovered in the by-products plant. In addition to the COG, daily production of these by-products include 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 35 tons of elemental sulfur, and 50 tons of anhydrous ammonia.

Clairton is located approximately 20 miles south of Pittsburgh on 392 acres along 3.3 miles of the west bank of the Monongahela River. The plant was built by St Clair Steel Company in 1901 and bought by U.S. Steel in 1904. The first coke batteries were built in 1918. The coke produced is used in the blast furnace operations in the production of molten iron for steel making.

Clairton is a major source of both NOx and VOC emissions.

Diagrams of the plant's operations are included in Clairton's Title V permit (issued March 27, 2012). A detailed description of the metallurgical coke production process with by-product recovery, including the nature and extent of air pollutant emissions is available in EPA's "Emission Factor Determination for AP-42 Section 12.2, Coke Production, Final Report" (May 2008).[2]

Producing coke in this manner generates large quantities of COG, which is used as fuel for the coke batteries (referred to as underfiring) and six boilers. Like natural gas, COG is a combustible gas with a high enough heating value to be used as fuel. However, unlike natural gas, the major combustible component of COG is hydrogen gas. In addition, COG has a heating value of about one-half that of natural gas.

Detailed descriptions of the emissions units for which a RACT evaluation was completed are provided in the following sections.

Source RACT History

In 1993, Clairton performed a RACT analysis as part of the 1-hour ozone standard requirements pursuant to Article XXI, Section 2105.06. A second RACT analysis was conducted in 2006 in response to the creation of the 8-hour ozone NAAQS.

Facility Changes since the 1993 and 2006 RACT Analyses

Over the past 15 years, U.S. Steel has undertaken a project to maximize the consumption and use of COG at Clairton. As a result, the amount of natural gas consumed by Clairton combustion units, actual NOx emissions, and fossil fuel usage for the combination of U.S. Steel facilities (Clairton, Edgar Thomson and Irvin) have been reduced.

Since completion of the 2006 RACT evaluations, the following changes have taken place at Clairton:

- Boiler 1 has been modified such that it can no longer combust coal and fuel oil.
- In 2008, a new coke battery (Battery C) was installed and replaced existing Batteries 7, 8 and 9. Battery C contains the latest emission control technology and emits less air pollution per ton of coke produced than the Batteries 7, 8, and 9. Battery C consists of 84 ovens

[2] Available at http://www.epa.gov/ttnchie1/ap42/ch12/bgdocs/b12s02_may08.pdf. Accessed December 2014.

which have a design production rate of 36.8 tons of coal charged per oven for a design coking time of 18 hours to produce 24.7 tons of blast furnace coke per oven. Battery C has a PROven (Pressure Regulated Oven) system, developed by Uhde Corporation with staged air combustion. Coke produced from Battery C is sent to a new coke screening station for rail car loading and offsite transport.

- In 2008, a Battery C Quench Tower was installed (IP 0052-I011). This tower and new settling basin are designed with a state-of-the-art Kiro-Nathaus baffle system to control particulate emissions - a first of its kind to be installed in the United States.

In 2013, two new quench towers (designated 5A and 7A-IP 0052-I014a) were installed. These towers and new settling basin are designed with a state-of-the-art Kiro-Nathaus baffle system to control particulate emissions.

Tables 3 and 4 provide a list of emissions units at the source that emit NOx and VOC, respectively. Detailed descriptions of the emissions units for which a RACT evaluation was completed are provided in the following sections.

RACT Analyses in this Document

The production of coke and coke by-products from a coke by-products recovery plant, like the Clairton plant, is comprised of numerous complex metallurgical and chemical processing systems. While by-product coke batteries are fundamentally designed and operated in a similar manner, each is unique. Those design and operating differences are the reason why coal processing rates, coke production rates, and the nature and extent of generated by-products vary considerably from plant-to-plant. For this reason, a comprehensive investigation and assessment of coke production operations was completed, and the RACT evaluations contained in this document are primarily based on the following resources:

- EPA's Alternative Control Techniques Document - NOx emissions from Iron and Steel Mills[3]
- EPA's Alternative Control Techniques Document - NOx emissions from Industrial/Commercial/Institutional Boilers[4]
- EPA's Compilation of Air Pollutant Emission Factors ("AP42")[5]
- EPA's Air Pollution Control Technology Fact Sheets[6]
- RTI International report to the EPA OAQPS titled "Evaluation of PM2.5 Emissions and Controls at Two Michigan Steel Mills and a Coke Battery" (dated February 7, 2006)[7]
- Midwest Regional Planning Organization report titled "Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis" (dated March 30, 2005)[8]
- RACT Revision Request for ArcelorMittal Monessen LLC (dated July 10, 2012)[9]
- Rule and Implementation Information for Coke Ovens: Pushing, Quenching and Battery Stacks (codified in 40 CFR Part 63, Subpart CCCCC)[10]

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[3] Available at http://www.epa.gov/ttn/catc/dir1/iron_act.pdf. Accessed December, 2014.
[4] Available at http://www.epa.gov/ttncatc1/dir1/icboiler.pdf. Accessed December, 2014.
[5] Available at http://www.epa.gov/ttn/chief/ap42/ch12/final/c12s02_may08.pdf. Accessed December, 2014.
[6] Available at http://www.epa.gov/ttncatc1/products.html. Accessed December, 2014.
[7] Available at http://www.epa.gov/pm/measures/detroit_steel_report_final_20060207.pdf. Accessed December, 2014.
[8] Available at http://www.ladco.org/reports/control/bart/iron_and_steel_mills.pdf. Accessed December, 2014.
[9] Available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/plans/plans/general/13_ArcelorMittal_RACT_Revsion_Request_2012.pdf. Accessed December, 2014.
[10] Available at http://www.epa.gov/ttn/atw/coke2/coke2pg.html. Accessed November, 2014.

- Economic Impact Analysis of Final Coke Ovens NESHAP - Final Report (dated September 2002)[11]

In general, two categories of NOx emission reduction techniques were considered during the RACT evaluation process: those designed to minimize NOx generation (aka "pollution prevention"), and those designed to reduce the amount of air pollution emitted to the atmosphere by capturing and/or destroying a portion of emissions generated (aka "add-on pollution control"). Low-NOx burners and flue gas recirculation are examples of the first category, while selective catalytic reduction and thermal oxidation are examples of the second.

Table 3 lists the emissions units at Clairton with a NOx PTE, and Table 4 lists the emissions units at Clairton with a VOC PTE. A RACT evaluation has been completed for each emissions unit/operation designated with a "Yes" in the 'RACT' column. The remaining sections of this document include the respective evaluations.

Note: As indicated by Tables 3 and 4, ACHD has determined that it is not necessary to conduct a RACT evaluation for a number of emission units/operations. More specifically:

- <u>NOx and VOC RACT for Battery C:</u> Permitted in 2008 as BACT for NOx and VOC, Battery C has been designed to minimize emissions to the greatest practical extent. (The NOx and VOC emissions from Battery C are typically less than 20 percent of the corresponding emissions from any other battery at Clairton.)
  - Battery C is designed with a "PROven" (Pressure Regulated Oven) system. Developed by Uhde Corporation, the PROven system utilizes staged air combustion as a NOx pollution prevention measure. This system also regulates pressure within each oven chamber where the collector main operates under a negative pressure during coking in order to significantly reduce fugitive emissions from the ovens during charging and coking. This design was determined to be BACT for NOx and VOC in 2008.
  - Battery C is equipped with an emergency flare, determined to be VOC BACT in 2008.
  - The Battery C Quench Tower is designed as a wet-quenching system with Kiro-Nathaus chevron-style baffles and was determined to be VOC BACT in 2008.

- <u>VOC RACT for the Pushing and Quenching operations of Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20:</u> VOC emissions from these processes are already minimized through compliance with the requirements of 40 CFR Part 63, Subpart CCCCC (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coke Ovens: Pushing, Quenching and Battery Stacks). The provisions of the NESHAP (finalized in 2003 and last amended in August 2006) to which Clairton is subject, constitute Maximum Achievable Control Technology (MACT). By definition, MACT, while designed to reduce volatile HAPs (which includes organic compounds and VOC) in this case, is at least as stringent as RACT.

  Additionally, in 2013, VOC RACT was determined for the pushing and quenching operations at Shenango Incorporated to be good engineering and air pollution control practices. Shenango operates a by-products recovery coke battery located in Allegheny County.

- <u>Light Oil Barge Loading System:</u> This system is equipped with a vapor recovery system that captures VOC emissions released during the transfer of light oil. Collected VOC are directed to the plant COG handling system. The VOC PTE of the system is less than 1.0 ton/yr and reported actual emissions are negligible. As a result, VOC RACT for the loading system has been determined to be the continued use of the vapor recovery system.

[11] Available at http://www.epa.gov/ttnecas1/regdata/EIAs/CokeEIA_Final.pdf. Accessed December, 2014.

- VOC RACT for Boilers No. 1, 2, R1, R2, T1 and T2: Each unit currently combusts COG/natural gas and is required to be operated and maintained according to good engineering and air pollution control practices at all times. These operating and maintenance requirements were determined to be BACT for VOC in 2013 at Shenango Incorporated for its COG and natural gas fired boilers. As a result, the aforementioned BACT has been selected as VOC RACT for Clairton's boilers because RACT (by design) is less stringent than BACT, and the BACT determination was made recently.

- Miscellaneous methanol usage: Methanol is used in three ways at Clairton. First, it is injected into compressed air lines during the winter months to prevent condensate from freezing. Second, it is added to battery sealing material during winter months to prevent freezing. Finally, it is also used to wash the cryogenic process vessel packing (i.e. quartzite stones) in preparation for maintenance or turnaround activities. These activities are classified as trivial and result in fugitive VOC emissions at numerous emission points throughout the source. According to Clairton, vendors and other steel industry operators have indicated that there are no suitable material substitutions for methanol in this capacity.

- NOx and VOC RACT for all other equipment (e.g. battery charging, battery traveling hot car, battery soaking, unspecified fugitives etc.): This decision was made based on the relatively low potential emissions from these units/operations and the understanding that is it extremely unlikely that any additional controls would be technically or economically feasible.

The RACT evaluations included in this document are:

A. RACT for NOx – Underfiring of Coke Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20
B. RACT for NOx – Desulfurization Plant
C. RACT for NOx – Emergency Flares
D. RACT for NOx – Boiler 1
E. RACT for NOx – Boiler 2
F. RACT for NOx – Boilers R1, R2, T1 and T2
G. RACT for VOC – Underfiring of Coke Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20
H. RACT for VOC – By-Products Recovery Plant
I. RACT for VOC – Desulfurization Plant

Table 3 - Emission Units with a NOx PTE at Clairton[5]

Unit ID	Emissions Unit	Capacity		NOx PTE	NOx Actuals	NOx RACT
		#	Units	(tpy)	(tpy)^^	
P001-P003	Underfiring from Coke Batteries 1-3	517,935	tpy coal (per battery)	1647.9	504	**yes**
P007-P009	Underfiring from Coke Batteries 13-15	545,675	tpy coal (per battery)	922.5	345	**yes**
P010, P011	Underfiring from Coke Batteries 19 and 20	1,002,290	tpy coal (per battery)	2237	1274	**yes**
P012	Underfiring from Coke Battery B	1,491,025	tpy coal (per battery)	820	362	**yes**
P046	Underfiring from Coke Battery C (1)	1,005,528	tpy coal (per battery)	461	17	no
P001-P003	Pushing from Coke Batteries 1-3	517,935	tpy coal (per battery)	NQ	16	no
P007-P009	Pushing from Coke Batteries 13-15	545,675	tpy coal (per battery)	NQ	21	no
P010, P011	Pushing from Coke Batteries 19 and 20	1,002,290	tpy coal (per battery)	NQ	24	no
P012	Pushing from Coke Battery B	1,491,025	tpy coal (per battery)	NQ	11	no
P046	Pushing from Coke Battery C	1,005,528	tpy coke (per battery)	NQ	1.6	no
P001-P003	Traveling hot car from Coke Batteries 1-3	420,822	tpy coke (per battery)	NQ	<0.1	no
P007-P009	Traveling hot car from Coke Batteries 13-15	443,361	tpy coke (per battery)	NQ	<0.1	no
P010, P011	Traveling hot car from Coke Batteries 19 and 20	814,361	tpy coke (per battery)	NQ	<0.1	no
P012	Traveling hot car from Coke Battery B	1,216,333	tpy coke (per battery)	NQ	<0.1	no
P046	Traveling hot car from Coke Battery C	816,992	tpy coke (per battery)	NQ	<0.1	no

Table 3 - Emission Units with a NOx PTE at Clairton (continued)

Unit ID	Emissions Unit	Capacity		NOx PTE	NOx Actuals	NOx RACT
		#	Units	(tpy)	(tpy)^^	
P001-P003	Soaking from Coke Batteries 1-3	420,822	tpy coke (per battery)	NQ	<0.1	no
P007-P009	Soaking from Coke Batteries 13-15	443,361	tpy coke (per battery)	NQ	<0.1	no
P010, P011	Soaking from Coke Batteries 19 and 20	814,361	tpy coke (per battery)	NQ	<0.1	no
P012	Soaking from Coke Battery B	1,216,333	tpy coke (per battery)	NQ	<0.1	no
P046	Soaking from Coke Battery C	816,992	tpy coke (per battery)	NQ	<0.1	no
P019	Desulfurization plant (incinerator) (2)	6,394,800	tpy coke	31.5	1.0	**yes**
B001	Boiler No. 1 (Babcock & Wilcox) (3)	760	MMBtu/hr (COG and NG)	1740	522.89	**yes**
B002	Boiler No. 2 (Combusting Engineering) (4)	481	MMBtu/hr (COG and NG)	1285	188.8	**yes**
B005	Boiler R1 (Riley Stoker) (4)	229	MMBtu/hr (COG and NG)	525	11.54	**yes**
B006	Boiler R2 (Riley Stoker) (4)	229	MMBtu/hr (COG and NG)	525	10.58	**yes**
B007	Boiler T1 (Erie City Zurn) (4)	156	MMBtu/hr (COG and NG)	358	11.5	**yes**
B008	Boiler T2 (Erie City Zurn) (4)	156	MMBtu/hr (COG and NG)	358	10.34	**yes**
-	Emergency Flares	varies	MMBtu/hr	19	8.67	**yes**
-	Misc. portable/seasonal space heaters	varies	MMBtu/hr (total)	NQ	NQ	no

^^ Actual emissions reported in 2012.
(1) Permitted in 2008. Designed with staged air combustion for NOx control.
(2) Desulfurization plant incinerator uses oxygen firing and FGR for NOx control.
(3) Uses fuel staging and low excess air for NOx control.
(4) Uses low excess air for NOx control.
(5) From US Steel 2014 RACT Submittal. Facility May want to lower permit limits if there is a large difference between potentials and actuals

Table 4 - Emission Units with a VOC PTE at Clairton[5]

Unit ID	Emissions Unit	Capacity		VOC Control	VOC PTE	VOC Actuals	VOC RACT
		#	Units		(ton/yr)	(ton/yr)^^	
P001-P003	Underfiring from Coke Batteries 1-3	517,935	tpy coal (per battery)	-	72.9	1.98	yes
P007-P009	Underfiring from Coke Batteries 13-15	545,675	tpy coal (per battery)	-	77.1	1.37	
P010, P011	Underfiring from Coke Batteries 19 and 20	1,002,290	tpy coal (per battery)	-	94	41.85	
P012	Underfiring from Coke Battery B	1,491,025	tpy coal (per battery)	-	70	1.3	
P046	Underfiring from Coke Battery C ^	1,005,528	tpy coal (per battery)	-	5.0	0.19	no
P001-P003	Charging (and associated leaks) from Coke Batteries 1-3	517,935	tpy coal (per battery)	-	NQ	0.36*	no
P007-P009	Charging (and associated leaks) from Coke Batteries 13-15	545,675	tpy coal (per battery)	-	NQ	0.37*	
P010, P011	Charging (and associated leaks) from Coke Batteries 19 and 20	1,002,290	tpy coal (per battery)	-	NQ	0.42*	
P012	Charging (and associated leaks) from Coke Battery B	1,491,025	tpy coal (per battery)	-	NQ	0.22*	
P046	Charging (and associated leaks) from Coke Battery C ^	1,005,528	tpy coal (per battery)	-	NQ	<0.1	

Table 4 - Emission Units with a VOC PTE at Clairton (continued)

Unit ID	Emissions Unit	Capacity		VOC Control	VOC PTE	VOC Actuals	VOC RACT
		#	Units		(ton/yr)	(ton/yr)^^	
P001-P003	Pushing from Coke Batteries 1-3	420,822	tpy coke (per battery)	-	NQ	1.36	no
P007-P009	Pushing from Coke Batteries 13-15	443,361	tpy coke (per battery)	-	NQ	0.9	
P010, P011	Pushing from Coke Batteries 19 and 20	814,361	tpy coke (per battery)	-	NQ	1.0	
P012	Pushing from Coke Battery B	1,216,333	tpy coke (per battery)	-	NQ	2.7	
P046	Pushing from Coke Battery C ^	816,992	tpy coke (per battery)	-	NQ	1.5	
P001-P003	Traveling hot car from Coke Batteries 1-3	420,822	tpy coke (per battery)	-	NQ	0.13*	no
P007-P009	Traveling hot car from Coke Batteries 13-15	443,361	tpy coke (per battery)	-	NQ	0.08*	
P010, P011	Traveling hot car from Coke Batteries 19 and 20	814,361	tpy coke (per battery)	-	NQ	0.07*	
P012	Traveling hot car from Coke Battery B	1,216,333	tpy coke (per battery)	-	NQ	0.0*	
P046	Traveling hot car from Coke Battery C ^	816,992	tpy coke (per battery)	-	NQ	0.09*	
P001-P003	Soaking from Coke Batteries 1-3	420,822	tpy coke (per battery)	-	NQ	0.93*	no
P007-P009	Soaking from Coke Batteries 13-15	443,361	tpy coke (per battery)	-	NQ	0.81*	
P010, P011	Soaking from Coke Batteries 19 and 20	814,361	tpy coke (per battery)	-	NQ	1.04*	
P012	Soaking from Coke Battery B	1,216,333	tpy coke (per battery)	-	NQ	0.49*	
P046	Soaking from Coke Battery C ^	816,992	tpy coke (per battery)	-	NQ	0.25*	

Table 4 - Emission Units with a VOC PTE at Clairton (continued)

Emissions Unit	Capacity		VOC Control	VOC PTE	VOC Actuals	VOC RACT
	#	Units		(ton/yr)	(ton/yr)^^	
Quench Tower No. 1	1,553,805	tpy coal	-	NQ	5.42*	no
Quench Tower No. 5	1,637,025	tpy coal	-	NQ	6.15*	
Quench Tower No. 6 (Alternate)	1,637,025	tpy coal	-	NQ	0.0*	
Quench Tower No. 7	2,004,580	tpy coal	-	NQ	9.2*	
Quench Tower No. 8 (Alternate)	2,004,580	tpy coal	-	NQ	0.0*	
Quench Tower No. B	1,491,025	tpy coal	-	NQ	13.8*	
Quench Tower No. C ^	?	tpy coal	-	NQ	10.2*	
Quench Tower No. 5A ^	?	tpy coal	-	NQ	0.002*	
Quench Tower No. 7A ^	?	tpy coal	-	NQ	0.004*	
Unspecified fugitives from Coke Batteries 1-3	-	-	-	NQ	8.4	no
Unspecified fugitives from Coke Batteries 13-15	-	-	-	NQ	7.56	
Unspecified fugitives from Coke Batteries 19 and 20	-	-	-	NQ	6.85	
Unspecified fugitives from Coke Battery B	-	-	-	NQ	3.0	
Unspecified fugitives from Coke Battery C ^	-	-	-	NQ	<3.0	
Desulfurization plant	6,394,800	tpy coke	(1)	398	71.5*	**yes**
By-Product Recovery Plant *	8,240,605	tpy coal	(2)	124	8.0	**yes**
Light oil barge loading system	55,000,000	gal/yr	(3)	0.75	0.04*	no
Boiler No. 1 (Babcock & Wilcox)	760	MMBtu/hr (COG and NG)	-	18.31	5.58	no
Boiler No. 2 (Combusting Engineering)	481	MMBtu/hr (COG and NG)	-	11.59	2.57	

Table 4 - Emission Units with a VOC PTE at Clairton (continued)

Unit ID	Emissions Unit	Capacity		VOC Control	VOC PTE	VOC Actuals	VOC RACT
		#	Units		(ton/yr.)	(ton/yr.)^^	
B005	Boiler R1 (Riley Stoker)	229	MMBtu/hr (COG and NG)	-	5.52	0.14	no
B006	Boiler R2 (Riley Stoker)	229	MMBtu/hr (COG and NG)	-	5.52	0.12	
B007	Boiler T1 (Erie City Zurn)	156	MMBtu/hr (COG and NG)	-	3.76	0.19	
B008	Boiler T2 (Erie City Zurn)	156	MMBtu/hr (COG and NG)	-	3.76	0.19	
-	Emergency Flares	varies	MMBtu/hr	(4)	0.49	<0.1	no
-	Misc. portable/seasonal space heaters	varies	MMBtu/hr (total)	-	NQ	NQ	no
-	Miscellaneous methanol usage	-	-	-	NQ	8.17	no
-	Wastewater treatment units and aeration basins	-	-	-	NQ	1.48	no
-	Parts Washer	-	-	-	NQ	1.65	no
-	Miscellaneous paints and thinners	-	-	-	NQ	6.74	no

^ Permitted in 2008.

^^ Reported actual emissions for CY 2012 as provided by source in RACT submittal

* Reported actual emissions for CY 2013

NQ - Not quantified

(1) Desulfurization plant uses an incinerator for VOC control.

(2) The By-Products Recovery Plant uses a clean COG gas blanketing system for VOC control.

(3) The light oil loading system captures VOC emissions with a vapor recovery system.
(4) By design, the emergency flares serve as VOC control.
(5) From US Steel 2014 RACT Submittal. Facility May want to lower permit limits if there is a large difference between potentials and actuals

A. RACT for NOx – Underfiring of Coke Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20

Process/Unit description - Underfiring

Clairton operates ten by-product coke oven batteries, each consisting of 64 to 87 ovens, identified as Batteries C, B, 1, 2, 3, 13, 14, 15, 19 and 20. (As explained previously in this document, Battery C is not addressed further.)

The coking process begins with the transfer, i.e. "charge", of coal through an opening in the top of the oven. Once the oven has been filled with coal and sealed, the oven is uniformly heated. Heat is produced from the combustion of COG in one-half of the flues - a process referred to as "underfiring" - while the remaining flues transport combustion exhaust gas through a heat exchanger (called a regenerator). (Flues are located within the walls of the each coke oven. Regenerators are massive structures made of refractory brick and are located beneath the ovens and heating flues.) Underfiring exhaust gases leaving the regenerators are routed to, and ultimately emitted from, a "combustion stack". Each coking cycle typically takes between 16 to 18 hours.

In addition to producing coke, a by-product coke battery is designed and operated to collect the COG evolved from coal during the coking process. The COG escapes through an opening at the top of the oven at both ends of the coking chamber. Each opening is fitted with an offtake pipe, which routes the COG to the collection main for processing.

There are numerous underfiring/oven design configurations for by-products coke batteries that have been used, and are being used, worldwide. The underfiring systems at the Clairton batteries can be divided into three broad categories:

- Gun-flue, with one combustion air-port per burner (Wilputte batteries 1, 2 and 3);
- Gun-flue, with multiple combustion air ports per burner (Carl Still batteries 13, 14, 15 and B); and
- Underjet (Koppers-Becker batteries 19 and 20).

In gun-flue batteries, fuel gas enters the battery from the gas distribution piping into a horizontal gas duct (gas-gun) constructed of refractory brick extending the length of each wall below the oven floor elevation. Short vertical flues (risers) branch vertically off the gas-gun and lead to a replaceable refractory nozzle brick containing a sized, calibrated opening which regulates the gas flow to each of the vertical flues.

- At the batteries with one combustion air-port per burner, preheated combustion air mixes with the fuel gas at the bottom of the heating flue.
- At the batteries with multiple combustion air ports per burner a portion of the preheated combustion air mixes with the fuel gas at the bottom of the heating flue, and the remaining combustion air is "staged" (i.e., it is introduced into the flue and mixed with the partially consumed fuel at refractory ports spaced along the height of the flue). The primary reason for staging the introduction of combustion air is to maintain an even vertical temperature over the height of the flue.

Underjet batteries are built with a "basement" beneath the regenerators. Fuel gas is distributed to the individual heating flues through a system of piping in the battery basement. The fuel gas passes vertically through burner piping equipped with an orifice or metering pin to regulate the gas flow to each flue. After flowing through the metering device, the fuel gas ascends through a vertical gas duct (riser) built integrally into the regenerator and flue support walls to the base of the heating flue. The Clairton underjet batteries include a feature whereby the fuel gas entering the risers passes through a venturi nozzle designed to extract a certain quantity of flue

gas (products of combustion) from the regenerator and mix it with the fuel gas as it travels to the burner. This dilution of the fuel/air mixture increases the length of the flame and, like the staged air design described above, flue gas recirculation in the underjet batteries is intended to maintain an even temperature over the height of the flue.

There are primarily two mechanisms in which NOx emissions are formed: thermal NOx and fuel NOx. Thermal NOx is generated when nitrogen reacts with oxygen (in the combustion air) in a high temperature environment. Fuel NOx is generated from oxidation of nitrogen compounds in the fuel. In a coke oven battery, the far majority of NOx emissions are generated from the combustion of COG in the underfiring heating flues. The COG that evolves in the oven does not come in contact with the underfire combustion gases.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, NOx emissions from coke battery underfiring could, in theory, be minimized and/or controlled with:

(a) Combustion Optimization
(b) Low NOx Burners
(c) Flue Gas Recirculation
(d) Low Excess Air
(e) Staged Combustion
(f) Selective Catalytic Reduction
(g) Selective Non-Catalytic Reduction
(h) Fuel Switching

A concise description of each of these technologies is as follows:

Pollution Prevention Techniques - Combustion Modifications

(a) Combustion Optimization

Combustion optimization involves conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms and actuators) and determining if equipment needs to be cleaned or repaired. Combustion optimization also includes conducting various tests to collect data on the combustion operation. This data is then analyzed to determine the combination of settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the device).

Tune-ups are used to improve efficiency and save money, reduce combustion emissions, and to ensure safe operations. A tune-up generally involves: conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms and actuators); determining if equipment needs to be cleaned, repaired, or replaced; investigating levels of excess air and emissions of NOx and CO; evaluating temperatures and pressures; and inspecting for leakage and condensate. The data is analyzed and adjustments made to determine the combination of settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

In a study by the North Carolina State University on the effect of tune-ups on state operated boilers[12], it was found that 1-5% fuel savings could be achieved. Although the effect on emissions was not reported, an emission decrease of 1-5% would have occurred based on the use of less fuel. However, additional NOx and CO emission reductions would be expected above those associated with efficiency improvements. It is difficult to predict the potential overall reduction in emissions that tune-ups of the underfiring system can achieve because the pre-tune-up status is unknown.

(b) Low NOx Burners (LNB)

LNB is a unique pollution prevention control option in the sense that it simply refers to a burner that has been designed to emit less NOx than conventional burners. LNB are usually designed to incorporate one or more combustion control techniques within the burner, such as staged combustion, fuel/air premixing, flue gas recirculation, low excess air, or a combination of these techniques. In all cases, the NOx emissions are controlled by lowering combustion zone temperatures to reduce the production of thermal NOx. [13]

(c) Flue Gas Recirculation (FGR)

FGR is a pollution prevention technique in which a portion, typically 15 to 30 percent, of the flue gas is recycled back to the primary combustion zone. This dilutes the combustion reactants, lowers the peak flame temperature and oxygen concentration of the primary combustion zone, and thereby lowers thermal NOx formation.[14]

(d) Low Excess Air (LEA)

Controlling excess air used during fuel combustion can substantially affect NOx formation by determining the amount of oxygen available for NOx reaction. At a given excess air level, NOx emissions increase as the temperature of the combustion zone increases. LEA is a burner optimization strategy in which the unit is operated at the lowest excess air level that provides efficient, reliable, safe and complete combustion.

With continuous emissions monitoring systems (CEMS) and feedback control, excess air can be accurately controlled to maintain a level that promotes optimum combustion and burning conditions in addition to lowering NOx emissions. Reducing excess air can also result in increased energy productivity - the amount of energy consumed per unit of production - which further reduces emissions.

(e) Staged Combustion

Staging of combustion air causes fuel combustion to occur in two distinct zones. In the first zone, only partial combustion is conducted in a fuel-rich, oxygen-poor flame zone. The lack of available oxygen minimizes the formation of thermal and fuel NOx. In the second, fuel-lean zone, additional (secondary) combustion air is added to complete the combustion process. The introduction of proportionally large quantities of cooler air keeps the combustion zone at a sufficiently low temperature to minimize NOx formation despite the availability of excess oxygen.

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[12] Eckerlin, Dr. Herbert M. and Eric W. Soderberg, USI Boiler Efficiency Program: A Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities. Prepared for the State Energy Office, NC Department of Administration. Revised 2/25/04.

[13] Boiler Emission Guide - Reference Guide, 3rd Edition. Cleaver Brooks. (2010) Available at: http://www.cleaverbrooks.com/uploadedFiles/Internet_Content/Reference_Center/Insights/Boiler%20Emissions%20Guide.pdf. Accessed January, 2015.

[14] Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised) (EPA-453/R-93-034). 1993. Available at: http://www.epa.gov/ttn/catc/dir1/procheat.pdf. Accessed December, 2014.

Add-on Pollution Control Techniques

(f) Selective Catalytic Reduction (SCR)

SCR is an add-on control technique that controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. NH3, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH3 reacts with NOx to form molecular nitrogen and water. The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures can range from 350°F to 1,100°F but typically is designed to occur between 600°F and 750°F, depending on the catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

Regenerative selective catalytic reduction (RSCR) is a combination of two well-established control technologies: regenerative thermal oxidation and SCR. By utilizing the direct contact regenerative heater technology (typically associated with an RTO), polluted air streams approximately 100-150 °F lower than otherwise required can be treated without supplemental preheating. NOx reduction takes place in SCR catalyst modules positioned above the heat transfer bed.[15]

(g) Selective Non-Catalytic Reduction (SNCR) (with Preheating)

Like SCR, SNCR operates by promoting the conversion of NO_x into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires a flue gas of 1700-2000 °F.[16] Units with flue gas temperatures within this range, residence times less than one second, and high levels of uncontrolled NO_x are good candidates for SNCR control.[17]

Units can be retrofitted for SNCR by installing injection nozzles through holes cut in the furnace wall. The nozzles are connected by piping to air or steam and chemical supplies. Bulk chemical storage is normally remote from the individual heater and can be used for more than one heater or boiler. The SNCR systems require rapid chemical diffusion in the flue gas. The injection point must be selected to ensure adequate flue gas residence time and to avoid tube impingement. Computer modeling can be used to develop the optimum injection points.[18]

(h) Fuel Switching

Fuel switching reduces NOx formation by reducing fuel NOx. By replacing high-nitrogen fuels with low-nitrogen fuels, the overall nitrogen available for oxidation is reduced, lowering NOx emissions. The primary fuel for the Clairton batteries is COG. However, under rare circumstances, stabilized natural gas may be used as underfiring fuel.

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[15] RSCR system to Reduce NOx Emissions from Boilers. Abrams, Richard and Faia, Robert. Proceedings of the 17th Annual North American Waste-to-Energy Conference (2009). Available at http://www.seas.columbia.edu/earth/wtert/sofos/nawtec/nawtec17/nawtec17-2363.pdf. Accessed February 2015.

[16] Northeast States For Coordinated Air Use Management (NESCAUM), and Praveen Amar. Applicability and Feasibility of NO_x, SO_2, and PM Emissions Control Technologies for Industrial Commercial, and Institutional Boilers. November, 2008 (Revised January 2009). http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf. Accessed January, 2015.

[17] U.S. EPA. Air Pollution Control Technology Fact Sheet; Selective Non-Catalytic Reduction (EPA-452/F-03-031). 2003. http://www.epa.gov/ttncatc1/dir1/fsncr.pdf. Accessed January, 2015.

[18] Id.

For example, a battery may be placed into "idle hot" condition because of market demand or other circumstances. During that time, the production of COG might be less than what is required for both the operating and idle batteries, so stabilized natural gas would be used to supply the deficit.

Step 2 – Eliminate Technically Infeasible Control Options

Each control option listed in Step 1 was evaluated to determine if it represents a technically feasible means of controlling NOx emissions from the underfiring of Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20. In summary, it was determined that, besides periodic tune-ups, there are no technically feasible control options.

(b - e) Low NOx Burners (LNB), Flue Gas Recirculation (FGR), Low Excess Air (LEA) and Staged Combustion (or any other form of combustion modifications):

The underfiring process, by virtue of its design, is ill-suited for retrofit emission reductions techniques for the following reasons:

- While other combustion processes (e.g. that of a boiler) can be highly tuned (via changes to over- and under- fire air, air-to-fuel ratios, exhaust recirculation etc.) to reduce emissions or accommodate changes in back pressure (created by add-on pollution control), a coke battery's underfiring system cannot. While the principle of all coke ovens is the same, each coke oven and oven operation is unique due to wide variations in the geometry of the combustion chambers, the combustion variables of fuel and air mixtures, temperature, humidity, and other factors.[19]

- With burners and heating/exhaust flues distributed throughout the battery oven walls and infrastructure, an entire battery would need to be dismantled and rebuilt to accommodate modifications to the underfiring system. Even if such an endeavor was completed, there is little information available regarding the effectiveness of the NOx control that would be achieved.

- Batteries are typically operated with relatively high excess combustion air with a flue gas O_2 range of approximately 8 to 12 percent. Excess air in coke ovens is needed to maintain compliance with other battery stack emissions regulations, and to assure complete combustion of the COG that can be subject to heating value variability.

- The underfiring process has a very large volumetric exhaust flow rate (approximately 56,000-102,000 dscf/min) and relies on certain flame temperatures and flame lengths to adequately produce coke products. Modifications to the underfiring system are likely to compromise requisite flame, air flow characteristics, system backpressure, and the quality of the coke produced.

- Clairton's standard operating procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. In doing so, the existing combustion optimization process functions as a fuel conservation method.

- Staged combustion for a coke battery underfiring process has been successfully designed and utilized by Battery C. However, that battery was originally designed with the pollution prevention technology and permitted for construction in 2008.

[19] Id.

- Staged combustion and FGR have been successfully applied to an existing coke battery underfiring process at the EES Coke production plant in Detroit, Michigan. However, the controls were incorporated into a new design of the battery when it was reconstructed in 1992.

- It is not possible to reduce the temperature of the preheated combustion air or the fuel. All of the batteries are constructed of refractory brick, and the regenerators are beneath the ovens and heating flues and are an integral part of the structure. Fuel passing through the gun-flues in Batteries 1-3, 13-15 and B or the risers in Batteries 19 and 20 is heated by the surrounding ovens, heating flues and regenerators. Revising the path of the fuel gas or combustion air to the burners would require complete reconstruction of the battery.

As a result, pollution prevention/combustion modifications - LNB, FGR, LEA and staged combustion - are not technically feasible control options for Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20.

Add-on Pollution Controls (SCR and SNCR)

The regenerators in COG-fired coke batteries increase fuel consumption efficiency by at least 35%[20]. This massive fuel savings directly translates to significant avoided emissions. However, in doing so, regenerators present design obstacles to post combustion NOx control. Air flow reversals occur every 20-30 minutes in typical batteries, and Clairton's batteries are operated with these industry-norm reversing cycles. The reversals result in step changes in temperature and flow to the battery underfiring stack. Air flow is actually stopped for the short period of time when the reverse occurs.

(f) Selective Catalytic Reduction (SCR)

Clairton's coke battery combustion and exhaust system does not operate with exhaust gas temperatures and airflows in the range where SCR can be effectively utilized. The average flue gas temperature of the combustion stack is approximately 493 °F; between 100 and 300 degrees cooler than what would be needed to ensure effective operation of an SCR.[21] Because of the massive exhaust airflow, preheating the exhaust would require additional fuel combustion that would significantly offset the emissions reductions achieved by the SCR.

According to literature research and discussions with vendors, it was determined that regenerative SCR (RSCR) has primarily been utilized to control NOx from relatively small biomass-fired boilers. There is no evidence that RSCR has been applied to a coke battery underfiring system.

In addition, the retroactive installation of a post-combustion NOx control, like SCR, would likely increase back pressure on the system and cause combustion process control to become erratic. This kind of process upset would likely result in increased emissions, poor coke quality and potentially compromise the integrity of the battery and the Clairton's ability to operate it safely. As a result, SCR is not technically feasible.

(g) Selective Non-Catalytic Reduction (SNCR)

There are no known applications, demonstrated or commercially operational, of SNCR to a coke oven battery underfiring/combustion system. In addition, there appears to be no

[20] *Coke Battery Heating, Theory and Practice*. USS Research Laboratory. 1982.
[21] Technical support document to Clairton's Title V permit.

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 NOx 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 NOx 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.

As a result, SNCR is not technically feasible.

(h) Fuel Switching

Natural gas must be first "stabilized" to match the characteristics of COG to be used as a primary fuel for underfiring. This is accomplished by adding air to the natural gas thus maintaining the same Wobbe index (Heating Value + Square root of specific gravity). Under similar combustion conditions for the batteries, NOx emissions from the combustion of natural are expected to exceed that of COG.

In addition, for every 1 MMBtu of natural gas that would be used to displace 1 MMBtu of COG for underfiring, the corresponding amount of COG would need to be flared (a wasteful scenario that would effectively double the NOx emissions from a coke battery).

As a result, using natural gas as the primary fuel for underfiring is not a feasible NOx control option.

The aforementioned control technology evaluations and assessments are substantiated by the following research:

- A review of the RACT-BACT-LAER-Clearinghouse (RBLC) database (Process Codes 81.112 and 81.190) and other publications indicates that an underfiring process at a by-product recovery coke plant has never been retrofitted with combustion modifications for NOx control, nor been equipped with any add-on NOx control.

In summary, the only technically feasible approach to reducing NOx emissions from battery underfiring (aside from completing periodic tune-ups) is to decommission a battery and construct a new one that is designed to emit lower levels of NOx. To do so would not only be cost prohibitive but is beyond the scope and authority of the RACT process.

Step 3 - Evaluate Control Options

Considering the design, operation and exhaust characteristics of the underfiring systems, periodic tune-ups have been determined to be the only technically feasible control option other than lowering permit limits based on emissions inventories or stack testing. As a result, this option was evaluated further.

Table 5 - Potential NOx Reductions from Technically Feasible Control Options – Underfiring

Technically Feasible Control Option	Estimated Control Efficiency	Potential NOx Emissions Reductions (ton/yr)[22]	Estimated Post-control NOx emissions (ton/yr.)
Tune ups	2%	6.15-22.4 (per battery)	301.4-1,096 (per battery)

[22] Determined as the boiler allowable PTE (ton/yr.) x Estimated control efficiency (%)

Using information provided by Clairton and collected by ACHD, an estimate of the costs associated with periodic tune-ups was completed - see Appendix A. The estimate is based on information provided in the following report: "USI Boiler Efficiency Program a Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities" February, 2004.[23]

Table 6. Economic Analysis of Technically Feasible Control Options – Underfiring (combined for all batteries)

Technically Feasible Control Option	Total Capital Investment for All Batteries($)	Total Annualized Cost for All Batteries ($/yr)	Potential NOx Removal for All Batteries (ton/yr)	Cost Effectiveness ($/ton NOx removed)
Tune ups	$58,500	$18,100	112.6	$161

2014 US Steel RACT submittal (0052c2014-04-17ract) Pages 32-33 PTEs are shown below:

- Battery 1 – 549.3 tpy
- Battery 2 – 549.3 tpy
- Battery 3 – 549.3 tpy
- Battery 13–307.5 tpy
- Battery 1 – 307.5 tpy
- Battery 15–307.5 tpy
- Battery 19–1118.7 tpy
- Battery 20–1118.7 tpy
- Battery B –820.1 tpy

These 2014 US Steel RACT submittal PTEs above are approximately the same as the TVOP PTEs for underfiring in worksheet "Table A-4a Underfire Stacks" of X:\Public Health Programs\Air Quality\AQ Common\AQ Documents\u\us steel clairton\permits\operating permits\draft\clairton – tv-calcs – draft.xlsx

TVOP application "0052op2001-03-02app" PTEs are shown below:

- Page 73 - Battery 1 – 564.8 tpy
- Page 103 – Battery 2 – 564.8 tpy
- Page 129 – Battery 3 – 564.8 tpy
- Page 242 – Battery 13 – 471.05 tpy
- Page 272 – Battery 14 – 471.05 tpy
- Page 299 – Battery 15 – 471.05 tpy
- Page 326 – Battery 19 – 2041.41 tpy
- Page 357 – Battery 20 – 2041.41 tpy
- Page 386 – Battery B – 722.55 tpy

These 2001 permit application PTEs above are higher than US Steel Clairton's 2014 RACT submittal "0052c2014-04-17ract" except for Battery B. Battery B is 820.1 tpy in the RACT submittal. However, these 2001 permit application PTEs are much older than those in both the 2014 RACT submittal from US Steel Clairton and the TVOP PTEs for underfiring.

[23] Available at http://infohouse.p2ric.org/ref/49/48741.pdf. Accessed April 2015.

With regards to emissions inventory and/or testing records, the potential emissions from underfiring for these batteries could be as follows:

265.63 tpy NOx for Battery 1; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 169.54 tpy (2010), 192.13 tpy (2011), 188.41 tpy (2012), 176.30 tpy (2013), and 183.35 tpy (2014). The actual emissions in the 2014 RACT submittal are 168.41 tpy. Page 19 of stack test report 0052str2013-11-06 1-2 combustion shows average test run of 230.98 tpy. Limit is average test run plus 15% = 230.98 tpy * 115% = 265.63 tpy]

175.40 tpy NOx for Battery 2; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 199.16 tpy (2010), 181.10 tpy (2011), 178.85 tpy (2012), 130.89 tpy (2013), and 136.62 tpy (2014). The actual emissions in the 2014 RACT submittal are 178.85 tpy. Page 21 of stack test report 0052str2013-11-06 1-2 combustion shows an average test run of 152.52 tpy. Limit is average test run plus 15% = 152.52 tpy * 115% = 175.40 tpy.]

230.50 tpy NOx for Battery 3; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 200.42 (2010), 198.62 (2011), 136.77 (2012), 135.06 (2013), and 148.34 (2014). The actual emissions in the 2014 RACT submittal are 136.77 tpy. Page 22 of stack test report 0052str2010-07-12battery 3 has an emission factor of 68.5 lbs NOx/hr. Assuming 8760 hrs/yr, this equates to 300.03 tpy. Limit is highest emissions inventory from the past five years times 115% = 200.42 * 115% = 230.50 tpy.]

201.83 tpy NOx for Battery 13; (I used stack test as limit for battery 13-15) [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 126.35 (2010), 129.75 (2011), 119.49 (2012), 107.80 (2013), and 110.45 (2014). The actual emissions in the 2014 RACT submittal are 119.48 tpy. Page 16 of stack test report 0052str2013-06-13batteries13-14 revised shows an average of 175.5 tpy. Limit is 175.5 tpy * 115% = 201.83 tpy]

166.41 tpy NOx for Battery 14; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 118.48 (2010), 121.81 (2011), 113.54 (2012), 98.92 (2013), and 99.16 (2014). The actual emissions in the 2014 RACT submittal are 113.53 tpy. Page 18 of stack test report 0052str2013-06-13batteries13-14 revised shows an average of 144.7 tpy. Limit is 144.7 tpy * 115% = 166.41]

174.82 tpy NOx for Battery 15; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 148.02 (2010), 152.02 (2011), 111.82 (2012), 75.36 (2013), and 51.26 (2014). The actual emissions in the 2014 RACT submittal are 111.82 tpy. Page 23 of stack test report 0052str2010-11-12battery15stack has an emission factor of 48.2 lbs NOx/hr. This equates to 211.12 tpy. Limit is highest inventory value from the past five years times 115% = 152.02 tpy * 115% = 174.82 tpy]

889.5 tpy NOx for Battery 19; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 344.24 (2010), 339.26 (2011), 773.45 (2012), 685.72 (2013), and 661.38 (2014). The actual emissions in the 2014 RACT submittal are 773.45 tpy. Page 24 of stack test report 0052str2011-01-24battery19stack has an emission factor of 134 lbs NOx/hr. This equates to 586.92 tpy. Limit is highest inventory value from the past five years times 115% = 773.45 tpy * 115% = 889.5 tpy]

941.9 tpy NOx for Battery 20; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 555.04 (2010), 546.23 (2011), 500.38 (2012), 522.24 (2013),

and 581.21 (2014). The actual emissions in the 2014 RACT submittal are 500.38 tpy. Page 24 of stack test report 0052str2011-01-24battery20stack has an emission factor of 187 lbs NOx/hr. This equates to 819.06 tpy. Limit = 819.06 tpy * 115% = 941.9 tpy.]

466.78 tpy NOx for Battery B; [ACHD NOx emissions inventories by year are as follows (NG and COG emissions combined): 444.43 (2010), 371.80 (2011), 361.91 (2012), 488.87 (2013), and 362.50 (2014). The actual emissions in the 2014 RACT submittal are 381.91 tpy. Page 18 of stack test report 0052str2013-09-16combustion stack shows 315.31 tpy. Limit is average of emissions inventory values times 115% = 466.78 tpy]

Step 4 – Select RACT

ACHD has determined that NOx RACT for the Underfiring of Coke Batteries B, 1, 2, 3, 13, 14, 15, 19, and 20 is:

1) Total NOx emissions for all batteries combined shall not exceed 3,513 tons per consecutive twelve month period.
2) The Underfiring systems must be properly maintained and operated at all times according to good engineering and air pollution control practices for minimizing emissions. [40 CFR 63.7300(a)]
3) An annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

    - Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
    - Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize emissions of CO; and
    - Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the Service Company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

B. RACT for NOx – Desulfurization Plant (DP)

Process/Unit description – Desulfurization Plant

Large quantities of COG are produced in the ovens during the coking process. The evolved COG exits the battery ovens through standpipes is spray-cooled to precipitate tar and condense various vapors and routed to the collection main. The collected COG is routed to the By-Products Recovery Plant (BPRP), where a variety of valuable organic compounds are extracted, and then further processed by the Desulfurization Plant (DP) where hydrogen sulfide (H2S) and other sulfur compounds are removed. Sulfur dioxide (SO2) emissions are generated from the oxidation of H2S present in COG when it is combusted.

Desulfurization processes vary considerably from coke production plant to coke plant. At Clairton, the DP primarily consists of two Claus Plants (one primary and one backup) and the Shell Claus Off-gas Treatment (SCOT) Plant. The Claus Plant converts a large portion of the H2S and other sulfur compounds in the treated COG to elemental sulfur which is sold. The treated COG exiting the Claus Plant is then routed to the SCOT Plant where it is processed and separated into three gas streams: a treated/low sulfur COG stream, a concentrated H2S stream and an acid off-gas stream. The H2S stream is returned/recycled to the Claus Plant for further sulfur removal and recovery. The acid off-gas stream is incinerated by the SCOT Plant Incinerator.

The concentration of H2S in the COG exiting the DP is typically reduced to approximately 10 grains per 100 dry standard cubic feet (dscf) of COG, or approximately 0.045 percent sulfur.

The SCOT Plant Incinerator is a regenerative-type unit that is designed with and uses oxygen-firing and FGR for NOx control. [This is listed in the 2014 US Steel RACT submittal, however ACHD records do not indicate the DP has such controls. Confirm this with the facility).

The unit's NOx PTE is 31.5 ton/year, and actual NOx emissions are approximately 1 ton/year [US Steel Clairton RACT submittal "0052c2014-04-17ract].

Source testing conducted in November of 2015 shows emissions of approximately 4.60 tpy.
[Page 18 of "0052str2016-01-25scot" shows the highest test run was 1.05 lb/hr of NOx. 1.05 lb/hr * 8760 hrs/yr * ton/2,000 lbs = 4.60 tpy]

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, NOx emissions from the SCOT incinerator could, in theory, be controlled with:

(a) Combustion Optimization
(b) Low NOx Burners
(c) Flue Gas Recirculation
(d) Selective Catalytic Reduction
(e) Selective Non-Catalytic Reduction

A concise description of each of these technologies is as follows:

Pollution Prevention Techniques - Combustion Modifications

(a) Combustion Optimization

Combustion optimization involves conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms, and actuators) and determining if equipment needs to be cleaned or repaired. Combustion optimization also includes conducting various tests to collect data on the combustion operation. This data is then analyzed to determine the combination of settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the device).

Tune-ups are used to improve efficiency and save money, reduce combustion emissions, and to ensure safe operations. A tune-up generally involves: conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms, and actuators); determining if equipment needs to be cleaned, repaired, or replaced; investigating levels of excess air and emissions of NOx and CO; evaluating temperatures and pressures; and inspecting for leakage and condensate. The data is analyzed and adjustments are made to determine the combination of settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

In a study by the North Carolina State University on the effect of tune-ups on state operated boilers[24], it was found that 1-5% fuel savings could be achieved. Although the effect on emissions was not reported, an emission decrease of 1-5% would have occurred based on the use of less fuel. However, additional NOx and CO emission reductions would be expected above those associated with efficiency improvements. It is difficult to predict the potential overall reduction in emissions that tune-ups of the SCOT Incinerator can achieve because the pre-tune-up status is unknown.

(b) Low NOx Burners (LNB)

LNB is a unique pollution prevention control option in the sense that it simply refers to a burner that has been designed to emit less NOx than conventional burners. LNB are usually designed to incorporate one or more combustion control techniques within the burner, such as staged combustion, fuel/air premixing, flue gas recirculation, low excess air, or a combination of these techniques. In all cases, the NOx emissions are controlled by lowering combustion zone temperatures to reduce the production of thermal NOx.[25]

(c) Flue Gas Recirculation (FGR)

FGR is a pollution prevention technique in which a portion, typically 15 to 30 percent, of the flue gas is recycled back to the primary combustion zone. This dilutes the combustion reactants, lowers the peak flame temperature and oxygen concentration of the primary combustion zone, and thereby lowers thermal NOx formation.[26]

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[24] Eckerlin, Dr. Herbert M. and Eric W. Soderberg, USI Boiler Efficiency Program: A Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities. Prepared for the State Energy Office, NC Department of Administration. Revised 2/25/04.

[25] Boiler Emission Guide - Reference Guide, 3rd Edition. Cleaver Brooks. (2010) Available at: http://www.cleaverbrooks.com/uploadedFiles/Internet_Content/Reference_Center/Insights/Boiler%20Emissions%20Guide.pdf. Accessed January, 2015.

[26] Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised) (EPA-453/R-93-034). 1993. Available at: http://www.epa.gov/ttn/catc/dir1/procheat.pdf. Accessed December, 2014.

Add-on Pollution Control Techniques

(d) Selective Catalytic Reduction (SCR)

SCR is an add-on control technique that controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. NH3, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH3 reacts with NOx to form molecular nitrogen and water. The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures can range from 350°F to 1,100°F, but typically is designed to occur between 600°F and 750°F, depending on the catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

(e) Selective Non-Catalytic Reduction (SNCR)

Like SCR, SNCR operates by promoting the conversion of NO_x into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires a flue gas of 1700-2000 °F.[27] Units with flue gas temperatures within this range, residence times less than one second, and high levels of uncontrolled NO_x are good candidates for SNCR control.[28]

Units can be retrofitted for SNCR by installing injection nozzles through holes cut in the furnace wall. The nozzles are connected by piping to air or steam and chemical supplies. Bulk chemical storage is normally remote from the individual heater and can be used for more than one heater or boiler. The SNCR systems require rapid chemical diffusion in the flue gas. The injection point must be selected to ensure adequate flue gas residence time and to avoid tube impingement. Computer modeling can be used to develop the optimum injection points.[29]

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[27] Northeast States For Coordinated Air Use Management (NESCAUM), and Praveen Amar. Applicability and Feasibility of NO_x, SO_2, and PM Emissions Control Technologies for Industrial Commercial, and Institutional Boilers. November, 2008 (Revised January 2009). http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf. Accessed January, 2015.

[28] U.S. EPA. Air Pollution Control Technology Fact Sheet; Selective Non-Catalytic Reduction (EPA-452/F-03-031). 2003. http://www.epa.gov/ttncatc1/dir1/fsncr.pdf. Accessed January, 2015.

[29] Id.

Step 2 – Eliminate Technically Infeasible Control Options

Each control option listed in Step 1 was evaluated to determine if it represents a technically feasible means of controlling NOx emissions from the SCOT incinerator. In summary, it was determined that periodic tune ups, SCR, and SNCR (with preheating of the exhaust gas) are technically feasible control options.

Conversely, LNB and FGR are not additional technically feasible because:

- The SCOT Incinerator burner nozzles, oxygen and fuel feed, and combustion chambers are already inherently designed for NOx reduction. Modifications to these components are not possible without impact on emission reduction performance of other pollutants; which could cause a violation of the performance requirements.
- The incinerator is a regenerative-type unit that already employs FGR as part of its design.

Step 3 - Evaluate Control Options. The SCOT Incinerator's exhaust ranges from 1,500-2,000 ^{o}F. A heat exchanger could be utilized to lower the exhaust temperature to a point that would accommodate SCR. Likewise, a heat exchanger could be utilized to ensure that the exhaust temperature remained high enough to accommodate SNCR. However, with actual NOx emissions of approximately 1 ton/year, any additional form of add-on pollution control would be cost prohibitive. A review of the RBLC and coke plant permits substantiates this conclusion; SCR and SNCR have not been utilized to reduce NOx emissions from desulfurization plant activities like that at Clairton.

Considering the design, operation, and exhaust characteristics of the SCOT Incinerator system, periodic tune-ups have been determined to be the only feasible control option. As a result, this option was evaluated further.

Table 7 - Potential NOx Reductions from Technically Feasible Control Options – SCOT Incinerator

Technically Feasible Control Option	Estimated Control Efficiency	Potential NOx Emissions Reductions (ton/yr)[30]	Estimated Post-control NOx PTE (ton/yr)
Tune ups	2%	0.63	30.82

Table 8. Economic Analysis of Technically Feasible Control Options – SCOT Incinerator

Technically Feasible Control Option	Total Capital Investment ($)	Total Annualized Cost ($/yr)	Potential NOx Removal (ton/yr)	Cost Effectiveness ($/ton NOx removed)
Tune ups	$6,500	$2,000	0.63	$3,200

Using information provided by Clairton and collected by ACHD, an estimate of the costs associated with periodic tune-ups was completed - see Appendix A. The estimate is based on information provided in the following report: "USI Boiler Efficiency Program a Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities" February, 2004.[31]

[30] Determined as the boiler allowable PTE (ton/yr) x Estimated control efficiency (%)
[31] Available at http://infohouse.p2ric.org/ref/49/48741.pdf. Accessed April 2015.

Step 4 – Select RACT

ACHD has determined that NOx RACT for the Desulfurization Plant SCOT incinerator is new NOx limits of 1.05 lb/hr and 4.60 tpy and compliance with the other current requirements established by Clairton's Title V permit enhanced by annual tune-ups. More specifically, the flare shall be installed, maintained, and operated in accordance with manufacturer specifications, and good engineering and air pollution control practices for minimizing emissions.

ACHD has determined that NOx RACT for the Desulfurization Plant SCOT Incinerator is:

1) NOx emissions shall not exceed 4.60 tons per consecutive twelve month period.
2) The SCOT Incinerator shall be installed, maintained and operated in accordance with manufacturer specifications, and good engineering and air pollution control practices for minimizing emissions. [§2105.03 and 2105.06.d.6]
3) An annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

    - Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
    - Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize emissions of CO; and
    - Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

C. RACT for NOx – Emergency Flares

Process/Unit description – Emergency Flares

Clairton operates a several emergency flares (EFs) that combust excess de-sulfurized COG that cannot be used as fuel in its boilers or for battery underfiring. In this capacity, an EF primarily functions a VOC control and a safety device. Without them, excess COG would accumulate near ground level and create a significant fire/explosion hazard.

According to the Technical Support Document to Clairton's Title V permit, the emergency flares are open flares, i.e., are not enclosed, and operate with a VOC destruction efficiency of 99 percent.

Step 1 – Identify Control Options

ACHD reviewed Clairton's RACT submittal and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA's RACT/BACT/LAER Clearinghouse (RBLC), EPA's *Compilation of Air Pollutant Emission Factors*[32], and EPA's Standards of Performance for Petroleum Refineries[33] to determine the available controls for flares.

Since add-on controls are not available for open flares, EPA performed flare studies as part of the development of new source performance standards for refineries (40 CFR 60, Subpart J) in 2012. Based on the EPA's flare studies, with the exception of the original design of flares or retrofit of flares with heavy opacity generation, changes or retrofits of existing flares do not normally result in a quantifiable reduction of NOx. In general, reductions of emissions from flares are based on good engineering practices and on minimization of fuel burned. These controls are discussed below:

(a) Good Engineering Practices

Good engineering practices are utilized to ensure emissions from the flare system are minimized. In general, owners or operators of flares are trained to monitor the flares to ensure that they are operated and maintained in conformance with their designs, ensuring that flares are operated in a smokeless manner with no visible emissions. These practices also ensure that operators maintain presence of the pilot flame when the gas is routed to the flare.

(b) Flare Minimization Plan

A flare minimization plan (FMP) incorporates measures identified to reduce flare emissions by reducing the frequency and magnitude of flaring events ("prevention measures"). In general, a FMP ensures that the flare is operated in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds, or essential operational needs. Prevention measures identified usually address flaring as a result of planned major maintenance, including startup and shutdown; flaring that may be reasonably expected to occur due to issues of gas quality or quantity;

[32] AP-42, Chapter 13.5 – Industrial Flares (September 1991). Available at: http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf. Accessed January 28, 2015.
[33] 40 CFR 60, Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (as last updated September 12, 2012). Available at: http://www.ecfr.gov/cgi-bin/text-idx?SID=222ed662fc535aa19e0acb4937942218&node=sp40.7.60.j_0a&rgn=div6. Accessed January 28, 2015.

and flaring caused by recurrent failure of air pollution control equipment, process equipment, or processes.

A FMP generally includes a description and technical information for each flare, a description of the equipment or procedures implemented within the last five years or planned to reduce flaring, and a description of prevention measures needed to perform certain facility activities without flaring. FMPs are usually updated on an annual basis to include any new prevention measures identified as a result of an investigation into the cause of flaring events that have occurred in the prior year.

Step 2 – Eliminate Technically Infeasible Control Options

Each control option listed in Step 1 was evaluated to determine if it represents a technically feasible means of controlling NOx emissions from the EFs.

(a) Good engineering practices

Good engineering practices (GEP) include the operation and maintenance of the flares in accordance with the flare design, including any manufacturer's specifications and accepted best practices. Such practices are recommended for optimal performance and are generally used throughout the industry.

In general, owners or operators of flares are trained to monitor the flares to ensure that they are operated and maintained in conformance with their designs. These practices also ensure that operators maintain presence of the pilot flame when the gas is routed to the flare. While it is understood that GEP are generally used to minimize flare emissions and comply with applicable regulatory requirements (e.g. ensuring that flares are operated in a smokeless manner with no visible emissions), a quantifiable relationship between the use of GEP and flare emissions is not available. As a result, this control measure is not evaluated further.

(b) Flare minimization plan (FMP)

A flare minimization plan (FMP) incorporates measures identified to reduce flare emissions by reducing the frequency and magnitude of flaring events ("prevention measures"). In general, a FMP ensures that the flare is operated in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds, or essential operational needs. Prevention measures identified usually address flaring as a result of planned major maintenance, including startup and shutdown; flaring that may be reasonably expected to occur due to issues of gas quality or quantity; and flaring caused by recurrent failure of air pollution control equipment, process equipment, or processes.

As a result, a FMP is considered a technically feasible NOx control option for the EFs.

Step 3 - Evaluate Control Options

FMPs do not result in specific NOx emissions reductions from a flare but instead reduce the flow to the flare that generates NOx. ACHD believes that it is in Clairton's best interest to minimize the amount of COG flared because:

- As the primary fuel for boilers and battery underfiring, flared COG represents the loss of a valuable resource.
- The potential or expected NOx emissions reductions attributed to a FMP cannot be estimated because the corresponding reductions depend on Clairton's ability to minimize

the use of the flare. As a result, the pollution reduction and cost-effectiveness of a FMP cannot be quantified for a flare that is used as a means to control VOC emissions and protect personnel/property.

- Clairton is already subject to ACHD Article XXI §2105.06.d.6, which designates RACT (for incinerators used primarily for air pollution control) as the installation, maintenance, and operation of the source in accordance with manufacturer's specifications.

The costs associated with the implementation of a FMP at Clairton are not anticipated to be significant. As described previously in this document, minimizing flared COG is already a standard operating practice for Clairton.

Step 4 – Select RACT

ACHD has determined that NOx RACT for the Emergency Flares is the development and implementation of a flare minimization plan. The flare minimization plan must include (requirements for the flare management plan are modeled after SCAQMD Rule 1118 and 40 CFR part 60, subpart J[a (40 CFR 60.103a (a)): [Note: The requirements for the flare management plan are modeled after SCAQMD Rule 1118 and 40 CFR part 60, subpart Ja (40 CFR 60.103a(a))- Bob Sidner]:

(A) A listing of all process units and ancillary equipment connected to the flare for each affected flare, including:

1. A complete description and technical specifications for each flare and associated knock-out pots, surge drums, water seals and flare gas recovery systems;
2. Detailed process flow diagrams of all upstream equipment and process units venting to each flare, identifying the type and location of all control equipment;

(B) An evaluation of the baseline flow to the flares, not including pilot gas flow or purge gas flow. Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

1. A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;
2. A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline.
3. Procedures to minimize discharges to the affected flare during each special condition.

(C) A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring; and a description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring for:

1. Planned, turnarounds and other scheduled maintenance, based on an evaluation of these activities during the previous five years;
2. Essential operational needs and the technical reason for which the vent gas cannot be prevented from being flared during each specific situation, based on supporting documentation on flare gas recovery systems, excess gas storage and gas treating capacity available for each flare; and
3. Emergencies, including procedures that will be used to prevent recurring equipment breakdowns and process upset, based on an evaluation of the adequacy of maintenance schedules for equipment, process and control instrumentation.

(D) The facility must follow the flare minimization plan and operate all flares in such a manner that minimizes all flaring except during emergencies, shutdowns, startups, turnarounds or essential operational needs.

(E) The plan should be updated periodically to account for changes in the operation of the flares, such as new connections to the flares or the installation of a flare gas recovery system, but the plan need be re-submitted to the Department only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline, or installs a flare gas recovery system.

In addition, the flares shall be installed, maintained, and operated in accordance with manufacturer specifications, and good engineering and air pollution control practices for minimizing emissions.

D. RACT for NOx – Boiler 1 (B001)

Process/Unit description – Boiler 1

Clairton uses a combination of six boilers to produce steam for various operations at the plant. Each boiler combusts COG as its primary fuel and natural gas as its secondary/backup fuel. When the previous RACT study was completed in 1996, all of Clairton's boilers, including Boiler 1 were capable of firing coal and fuel oil. Since that time, the boilers have undergone two noteworthy changes. First, each boiler is currently only permitted to fire COG or natural gas. Second, automation upgrades have been completed which have resulted in more-efficient boiler operation and lower emissions.

Boiler 1 has a heat input capacity of 760 MMBtu/hr (HHV) and is the only cyclone-type unit at the plant. Boiler 1 is the only base-loaded boiler; continuously operated at 50-75% rated load throughout the year to satisfy the plant's primary steam demands and is only shutdown for annual maintenance.

Pursuant to Condition V.AA.1 of Clairton's Title V permit:

- NOx emissions from Boiler 1 are limited to 0.54 lb/MMBtu, 410.40 lb/hr and 1,740 tons per twelve consecutive month period.
- Boiler 1 shall have properly maintained and operated Continuous Monitoring Systems or approved alternatives for continuously monitoring the NOx concentration in the exhaust gas, meeting all the requirements of §2108.03 at all times with the exception of emergency or planned outages, repairs, or maintenance.
- Boiler 1 shall be properly maintained and operated according to good engineering and air pollution control practices at all times.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, NOx emissions from Boiler 1 could, in theory, be controlled with:

(a) Combustion Optimization
(b) Reduced Air Preheat
(c) Low Excess Air
(d) Staged Combustion - Air Staging
(e) Staged Combustion - Fuel Staging
(f) Fuel Re-burn
(g) Water/Steam Injection
(h) Flue Gas Recirculation
(i) Low NOx Burners
(j) Selective Catalytic Reduction
(k) Selective Non-Catalytic Reduction
(l) Oxidant Injection with Absorption
(m) Non Thermal Plasma Reactor
(n) Fuel Switching

These control measures have been organized into six categories: combustion optimization, staged combustion, additions to combustion air or fuel, burner replacement, post combustion controls, and fuel switching.

Pollution Prevention Techniques - Combustion Modifications

Boiler operation can be optimized to reduce NOx emissions by modifying boiler control settings. Sources can conduct a combustion optimization evaluation to determine the optimal settings for operating the boiler to address NOx emissions, as well as other factors. Alternatively, sources can specifically reduce the air preheat and/or the level of excess air to reduce NOx.

(a) Combustion Optimization

Combustion optimization involves conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms and actuators) and determining if equipment needs to be cleaned or repaired. Also, combustion optimization includes conducting various tests to collect data on the boilers operation. This data is then analyzed to determine the combination of settings that results in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

Tune-ups are used to improve efficiency, save money, reduce combustion emissions, and to ensure safe operations. A tune-up generally involves: conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms and actuators); determining if equipment needs to be cleaned, repaired, or replaced; investigating levels of excess air and emissions of NOx and CO; evaluating temperatures and pressures; and inspecting for leakage and condensate. The data is analyzed and adjustments are made to determine the combination of settings that results in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

In a study by the North Carolina State University on the effect of tune-ups on state operated boilers[34], it was found that 1-5% fuel savings could be achieved. Although the effect on emissions was not reported, an emission decrease of 1-5% would have occurred based on the use of less fuel. However, additional NOx and CO emission reductions would be expected above those associated with efficiency improvements. It is difficult to predict the overall reduction in emissions that tune-ups can achieve because the pre-tune-up status is unknown.

(b) Reduced Air Preheat (RAP)

Boiler combustion air can be preheated using boiler exhaust to improve boiler efficiency. However, the technique can inherently increase NOx emissions because flame temperature is increased (relative to an identical boiler without preheating). Air preheaters are typically used on coal stoker grate water-tube boilers with a heat input capacity greater than 100 MMBtu/hr.[35]

RAP is a technique in which the primary combustion zone peak temperature is lowered by reducing the preheating of combustion air. One notable advantage of this strategy is that no significant capital expenses for new or modified hardware are required.

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[34] Eckerlin, Dr. Herbert M. and Eric W. Soderberg, USI Boiler Efficiency Program: A Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities. Prepared for the State Energy Office, NC Department of Administration. Revised 2/25/04.
[35] Id.

(c) Low Excess Air (LEA)

Controlling excess air used during fuel combustion can substantially affect NOx formation by determining the amount of oxygen available for NOx reaction. At a given excess air level, NOx emissions increase as the temperature of the combustion zone increases. LEA is a burner optimization strategy in which the combustion unit is operated at the lowest excess air level allowable (i.e. a level that provides efficient, reliable, safe and complete combustion). The reduction in excess air typically reduces NOx emissions by 10% (in natural gas-fired units) and reduces the total flue gas flow and improves heat transfer.[36] With CEMS and feedback control, excess air can be accurately controlled to maintain a level that promotes optimum combustion and burning conditions in addition to lowering NOx emissions. Reducing excess air can also result in increased energy productivity (the amount of energy consumed per unit of production) which further reduces emissions.

Precise implementation of LEA is necessary to avoid incomplete combustion that may result in a decrease in energy efficiency, a decrease in steam temperature, and a significant increase in CO emissions. Without a strict control system, these characteristics can also lead to corrosion, opacity concerns, and even fires in air preheaters and ash hoppers (where applicable). One notable advantage of this strategy is that significant capital expenses for new or modified hardware are not required.

Staged Combustion

Staged combustion relies on the reduction of the peak flame zone temperature (and/or oxygen levels) to reduce NOx formation, and is achieved by delaying or staging the addition of combustion air.

(d) Air Staging

Air staging can be carried out using overfire air (OFA) or two-stage combustion. With air staged combustion, the combustion air is controlled and distributed to create different combustion zones. The flame temperature is consequently reduced, which reduces the NOx created. In the first zone, the air is sparingly distributed to create an initial sub-stoichiometric fuel rich zone. In the second zone above the first, the air is generously introduced to complete the combustion in a high excess air, low temperature zone, reducing thermal NOx formation.

(e) Fuel Staging

Staged fuel combustion can be accomplished using burners out of service (BOOS), biasing the fuel flow to specific burners (a.k.a., biased firing), and fuel re-burning. These methods create different zones of fuel burning, such as fuel rich and fuel lean zones, within the combustion unit by shutting off fuel flow, diverting fuel from specific burners, or by controlling air and fuel injection zones. Separating the combustion zones reduces the flame temperature, thereby reducing NOx. BOOS and biasing the fuel flow to specific burners cannot be conducted on boilers with only one burner because these are techniques that use multi-burners. Staged fuel combustion can achieve up to 50% NOx reduction.

(f) Fuel Re-burn

Fuel re-burning is a staged fuel combustion technique where fuel is introduced downstream of the primary combustion chamber to create a secondary combustion zone. However,

[36] Cleaver Brooks Boiler Emission Guide - Reference Guide. 3rd Edition. Available at http://www.cleaverbrooks.com/uploadedFiles/Internet_Content/Reference_Center/Insights/Boiler%20Emissions%20Guide.pdf. Accessed February 2015.

with fuel re-burning, the NOx formed in the primary combustion area is destroyed in the re-burn area. The additional fuel is often natural gas. Emission reductions of up to 60% are possible.[37]

Additions to Combustion Air or Fuel

Boiler operation can be optimized to reduce NOx emissions by injecting flue gases, water (or steam), oxygen, or other materials into the combustion zone or the fuel. This addition reduces NOx formation by altering the stoichiometric ratio of the combustion reactants. Typically, injected components (e.g. flue gas or steam) dilutes the combustion zone and reduces the temperature of the combustion zone and reduces the formation of thermal NOx. When oxygen is added, it displaces an equivalent amount of air and therefore reduces the amount of nitrogen available for NOx formation.

(g) Water/Steam Injection (WSI)

As the name suggests, WSI involves the injection of water (or steam) into the primary combustion zone to reduce peak flame temperature and decreases NOx formation. More specifically, this process dilutes the combustion gas stream and functions as a heat sink; i.e. a portion of the available thermal energy is used to vaporize the water and raise the vaporized water temperature to the combustion temperature. WSI is a proven technology for oil-fired, coal-fired boilers, and combustion turbines, with a NOx reduction potential of up to 80% in natural gas-fired units.[38]

(h) Flue Gas Recirculation (FGR)

FGR is a technique in which a portion of the (inert) flue gas is recycled back to primary combustion zone. As a result, it reduces the formation of thermal NOx by lowering peak flame temperature and reducing the concentration of oxygen. FGR typically reduces emissions of NOx in a natural gas boiler by about 53 to 74%.[39]

Burner Replacement

(i) Low NOx Burners (LNB)

LNB is a unique pollution prevention control option in the sense that it simply refers to a burner that has been designed to emit less NOx than conventional burners. LNB are usually designed to incorporate one or more combustion control techniques within the burner such as staged combustion, fuel/air premixing, flue gas recirculation, low excess air, or a combination of these techniques. In all cases, the NOx emissions are controlled by lowering combustion zone temperatures to reduce the production of thermal NOx. [40]

LNB is a relative term in the sense that is has evolved over time. For example, a 25-year old combustion unit "equipped with LNB" may have a NOx emission rate of approximately 50 ppm, while a new unit "equipped with LNB" may have a NOx emission rate of less than 30 ppm.[41] LNB technology is available from many manufacturers and applicable to all

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[37] Northeast States For Coordinated Air Use Management (NESCAUM), and Praveen Amar. Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for Industrial Commercial, and Institutional Boilers. November, 2008 (Revised January 2009). http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf. Accessed February 2015.
[38] Id.
[39] Id.
[40] Id.
[41] Id.

fuels. Low NOx burners typically achieve NOx reductions of 2 to 71 percent over conventional burners.[42]

Add-on Pollution Control Techniques

(j) Selective Catalytic Reduction (SCR)

SCR is an add-on control technique that controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. NH3, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH3 reacts with NOx to form molecular nitrogen and water. The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures can range from 350°F to 1,100°F but typically is designed to occur between 600°F and 750°F, depending on the catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

(k) Selective Non-Catalytic Reduction (SNCR)

Like SCR, SNCR operates by promoting the conversion of NO_x into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires a flue gas of 1700-2000 °F.[43] Units with flue gas temperatures within this range, residence times less than one second, and high levels of uncontrolled NO_x are good candidates for SNCR control.[44]

Units can be retrofitted for SNCR by installing injection nozzles through holes cut in the furnace wall. The nozzles are connected by piping to air or steam and chemical supplies. Bulk chemical storage is normally remote from the individual heater and can be used for more than one heater or boiler. The SNCR systems require rapid chemical diffusion in the flue gas. The injection point must be selected to ensure adequate flue gas residence time and to avoid tube impingement. Computer modeling can be used to develop the optimum injection points.[45]

(l) Oxidant Injection with Absorption

This technique involves two stages. First, an oxidant (ozone or hydrogen peroxide) is injected and mixed into the exhaust of a combustion unit. NOx within the air flow is oxidized to its water-soluble higher valence states (e.g. NO_3). Second, a gas absorber is subsequently used to remove the water-soluble NOx from the gas stream. Water, hydrogen peroxide, or an alkaline fluid typically function as the absorbent.[46]

(m) Non Thermal Plasma Reactor

Ammonia, methane, or hexane may be used as reducing agents to react with NOx in exhaust gas within an electron beam generated plasma. Ionized reducing agents are created by a transient high voltage which reacts with NOx for a removal of greater than 94 percent.[47]

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[42] Id.
[43] Id.
[44] U.S. EPA. Air Pollution Control Technology Fact Sheet; Selective Non-Catalytic Reduction (EPA-452/F-03-031). 2003. http://www.epa.gov/ttncatc1/dir1/fsncr.pdf. Accessed January, 2015.
[45] Id.
[46] U.S. EPA. Technical Bulletin; Nitrogen Oxides, Why and How They Are Controlled (EPA 456/F-99-006R). November: 1999. Available at http://www.epa.gov/ttncatc1/dir1/fnoxdoc.pdf, accessed January 2015.
[47] Id.

Fuel Switching

(n) Fuel Switching - Natural Gas

Fuel switching reduces NOx formation by reducing fuel NOx. By replacing high-nitrogen fuels with low-nitrogen fuels, the overall nitrogen available for oxidation is reduced, lowering NOx emissions. The primary fuel for the Clairton batteries is COG. However, under rare circumstances, stabilized natural gas may be used as underfiring fuel.

Step 2 – Eliminate Technically Infeasible Control Options

Each control option listed in Step 1 was evaluated to determine if it represents a technically feasible means of controlling NOx emissions from Boiler 1. In summary, it was determined that SCR and SNCR are technically feasible control options, the economic feasibility of which is evaluated in Step 3.

(b)-(f) Various Types of Combustion Modifications and (i) Low NOx Burners

In response to the 1996 RACT process, Boiler 1 has been tuned and modified for optimal efficiency. Specifically, Boiler 1 already uses fuel staging (a form of staged combustion) and low excess air to reduce the NOx generated by the unit. More specifically, Boiler 1's bottom burners operate with a fuel rich combustion zone and the top burners operate with a fuel lean combustion zone.

A review of 2013 CEMS data (for Boiler 1 and Boiler 2) indicates that each boiler's average annual NOx emission rate is typically <50% of the permitted 0.54 lb/MMBtu NOx emission limit. Manufacturers of burners have indicated (i.e. quoted) that replacement LNB would not reduce NOx emissions beyond what is currently being achieved. [NOTE: LNBs are listed here as infeasible with respect to the current permit limit].

Achieving further NOx reductions from combustion modifications or boiler tuning are not expected to be feasible. A retrofit of boiler design would need to be modeled and analyzed using computer simulation to determine if NOx emission reductions could be achieved and to what extent. For this reason, combined with the existing NOx control measures (staged combustion and low excess air), boiler consultants and vendors contacted by US Steel would not provide quotes for any form of combustion modifications or controls.

As a result, additional combustion modifications including the addition of LNB are considered to be technically infeasible control options for reducing NOx emissions.

(g) Water/Steam Injection

Water/steam injection (WSI) has been proven to reduce NOx emissions but does so with significant operational drawbacks, namely: reduced thermal efficiency, reduced steam production, and increased equipment corrosion. For these reasons, WSI has been primarily used on gas turbines where the reduction in thermal efficiency (and the resulting increase in fuel consumption) is much less than that which would be experienced by a steam boiler.

WSI is considered to be a technically infeasible control option for reducing NOx emissions.

(h) Flue Gas Recirculation (FGR)

Operation of Boiler 1 has been tuned for low excess air to reduce NOx emissions. Further suppression/reduction of air by any means would likely terminate the flame, and even the pilot, leading to incomplete combustion. If that scenario was to occur, VOC and opacity emissions would increase and likely result in permit violations.

As a result, FGR is considered to be a technically infeasible control option for reducing NOx emissions.

(n) Fuel switching

COG has already been determined to be the ideal primary fuel for each boiler at Clairton.

(l) – (m) Oxidant Injection with Absorption and Non-Thermal Plasma Reactor

There is no evidence that oxidant injection with absorption or a non-thermal plasma reactor has been successfully used with an industrial/commercial/institutional boiler, let alone a COG-fired boiler. As a result, oxidant injection with absorption and non-thermal plasma reactor are considered to be undemonstrated technologies and technically infeasible control options for reducing NOx emissions.

Step 3 - Evaluate Control Options

Periodic tune-ups, SCR, and SNCR have been determined to be technically feasible control options considering the exhaust characteristics of Boiler 1 and the demonstrated effectiveness of various technologies on other boiler systems. As a result, these options were evaluated further.

NOx emissions from Boiler 1 are limited to 0.54 lb/MMBtu, 410.40 lb/hr, and 1,740 tons per twelve consecutive month period. The following table presents the estimated control efficiency and potential NOx reductions of the technically feasible control options.

Table 9 - Potential NOx Reductions from Technically Feasible Control Options for Boiler 1

Technically Feasible Control Option	Estimated Control Efficiency	Potential NOx Emissions Reductions (ton/yr)[48]	Estimated Post-control NOx emissions (lb/MMBtu)
Tune ups	2%	35	<0.54
SCR	90%	1,566	0.054
SNCR	45%	783	0.297

Using information provided by US Steel and collected by ACHD, a thorough economic analysis of SCR and SNCR was conducted - see Appendix A. The assessment for tune-ups is based on information provided in the following report: "USI Boiler Efficiency Program a Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities" February, 2004.[49] The SCR and SNCR analyses consider the total costs associated with the NOx control equipment, including the total capital investment of the various components intrinsic to the complete system, the estimated annual operating costs, and indirect annual costs. All costs, and nearly all calculated values used to determine costs, were

[48] Determined as the boiler allowable PTE (ton/yr) x Estimated control efficiency (%)
[49] Available at http://infohouse.p2ric.org/ref/49/48741.pdf. Accessed April 2015.

determined using the methodology described in the "EPA Air Pollution Control Cost Manual, Sixth Edition" (document # EPA 452-02-001) and other technical resources available in the EPA Clean Air Technology Center.

Calendar year 1998 data was the basis of the cost estimates and appropriately updated using the Chemical Engineering Plant Cost Index (an accepted approach for RACT/BACT/BART analyses). While other indices were considered, such as the Consumer Price Index and the Producers Price Index, the Chemical Engineering Plant Cost Index was the most comprehensive fit for the collection of equipment and structures covered by this analysis.

Since COG and blast furnace gas (BFG) are already fully used by the US Steel processes, fuel costs were based on the purchase of natural gas for any supplemental heat. Natural gas pricing was based on the U.S. Energy Information Administration and natural gas pricing for industrial users in Pennsylvania (latest available report). Electric costs were also based upon this reference. Cost figures were also supplemented by use of other published documents, such as the previously referenced Midwest States BART document for Iron and Steel Mills, as well as vendor provided information (where available). Certain items used in the analysis were based on site-specific or U.S. Steel specific information, such as the interest rate on capital, natural gas cost, ammonia costs, and vendor quotes.

Annualized costs are based on an interest rate of 7%, and an equipment life of 15 years. The basis of cost-effectiveness, used to evaluate control options, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost analysis is provided the following table:

Table 10. Economic Analysis of Technically Feasible Control Options for Boiler 1[a]

Technically Feasible Control Option	Total Capital Investment ($)	Total Annualized Cost ($/yr)	Potential NOx Removal (ton/yr)	Cost Effectiveness ($/ton NOx removed)
Tune ups	$6,500	$2,000	35	$60
SCR	$13,224,600	$10,853,500	1,566	$6,900
SNCR	$3,652,000	$29,965,700	783	$38,300

The large annualized cost for both SCR and SNCR is dominated by the significant increase in supplemental natural gas that would be consumed. The requisite fuel consumption is necessary to heat the boiler exhaust to the minimum SCR and SNCR operating temperatures.

With a calculated cost-effectiveness of more than $38,000 per ton of NOx removed, ACHD has determined that SNCR is not an economically feasible control option for Boiler 1. With a calculated cost effectiveness of $6,900 per ton of NOx removed, ACHD has determined that SCR is not an economically feasible control option for Boiler 1.

Step 4 – Select RACT

ACHD has determined that NOx RACT for Boiler 1 is:

1. Continued compliance with permit conditions.
2. An annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize emissions of CO; and
- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

[a] NOTE: ERG's NOx RACT evaluation for Boilers 1, 2, R1, R2, T1 and T2 determined that SCR was cost effective at $6,000 - $7,800 per ton of NOx removed (based on PTE). However, according to the Title V TSD, the 2012 NOx RACT determinations completed by ACHD state that SCR is not technically feasible (no explanation) for Boilers 1 and 2, and not economically feasible for Boilers R1, R2, T1 and T2 (no supporting documentation). Given that actual emissions for Boilers R1, R2, T1 and T2 are approximately 3% of PTE, Clairton can easily accept more stringent NOx limits to make SCR cost prohibitive by a large margin. The same scenario applies to Boiler 1 and 2, but to a lesser extent. As a result, the NOx RACT evaluations do not include proposed RACT limits. Ultimately, ERG expects Clairton to accept more stringent NOx limits that cause SCR to be cost prohibitive (like SNCR) and consequently make RACT equal to annual tune-ups.

E. RACT for NOx – Boiler 2

Process/Unit description – Boiler 2

Clairton uses a combination of six boilers to produce steam for various operations at the plant. Each boiler combusts COG as its primary fuel and natural gas as its secondary/backup fuel. Boiler 2 has a heat input capacity of 481 MMBtu/hr (HHV) and is the only four-wall-fired-type unit at the plant. It is also the only swing-loaded boiler; continuously operated at varying load throughout the year to satisfy the plant's primary steam demands and is only shutdown for annual maintenance.

Pursuant to Condition V.BB.1 of Clairton's Title V permit:

- NOx emissions from Boiler 2 are limited to 0.54 lb/MMBtu, 259.74 lb/hr, and 1,285 tons per twelve consecutive month period.
- Boiler 2 shall have properly maintained and operated Continuous Monitoring Systems or approved alternatives for continuously monitoring the NOx concentration in the exhaust gas, meeting all the requirements of §2108.03 at all times with the exception of emergency or planned outages, repairs or maintenance.
- Boiler 2 shall be properly maintained and operated according to good engineering and air pollution control practices at all times.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, NOx emissions from Boiler 2 could, in theory, be controlled with:

(a) Combustion Optimization
(b) Reduced Air Preheat
(c) Low Excess Air
(d) Staged Combustion - Air Staging
(e) Staged Combustion - Fuel Staging
(f) Fuel Re-burn
(g) Water/Steam Injection
(h) Flue Gas Recirculation
(i) Low NOx Burners
(j) Selective Catalytic Reduction
(k) Selective Non-Catalytic Reduction
(l) Oxidant Injection with Absorption
(m) Non Thermal Plasma Reactor
(n) Fuel Switching

These control measures have been organized into six categories: combustion optimization, staged combustion, additions to combustion air or fuel, burner replacement, post combustion controls, and fuel switching.

Pollution Prevention Techniques - Combustion Modifications

Boiler operation can be optimized to reduce NOx emissions by modifying boiler control settings. Sources can conduct a combustion optimization evaluation to determine the optimal settings for operating the boiler to address NOx emissions as well as other factors. Alternatively, sources can specifically reduce the air preheat and/or the level of excess air to reduce NOx.

(a) Combustion Optimization

Combustion optimization involves conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms, and actuators) and determining if equipment needs to be cleaned or repaired. Also, combustion optimization includes conducting various tests to collect data on the boilers operation. This data is then analyzed to determine the combination of settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

Tune-ups are used to improve efficiency and save money, reduce combustion emissions, and to ensure safe operations. A tune-up generally involves: conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms, and actuators); determining if equipment needs to be cleaned, repaired, or replaced; investigating levels of excess air and emissions of NOx and CO; evaluating temperatures and pressures; and inspecting for leakage and condensate. The data is analyzed and adjustments are made to determine the combination of settings that results in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

In a study by the North Carolina State University on the effect of tune-ups on state operated boilers[50], it was found that 1-5% fuel savings could be achieved. Although the effect on emissions was not reported, an emission decrease of 1-5% would have occurred based on the use of less fuel. However, additional NOx and CO emission reductions would be expected above those associated with efficiency improvements. It is difficult to predict the overall reduction in emissions that tune-ups can achieve because the pre-tune-up status is unknown.

(b) Reduced Air Preheat (RAP)

Boiler combustion air can be preheated using boiler exhaust to improve boiler efficiency. However, the technique can inherently increase NOx emissions because flame temperature is increased (relative to an identical boiler without preheating). Air preheaters are typically used on coal stoker grate water-tube boilers with a heat input capacity greater than 100 MMBtu/hr.[51]

RAP is a technique in which the primary combustion zone peak temperature is lowered by reducing the preheating of combustion air. One notable advantage of this strategy is that no significant capital expenses for new or modified hardware are required.

(c) Low Excess Air (LEA)

Controlling excess air used during fuel combustion can substantially affect NOx formation by determining the amount of oxygen available for NOx reaction. At a given excess air level, NOx emissions increase as the temperature of the combustion zone increases. LEA is a burner optimization strategy in which the combustion unit is operated at the lowest excess air level allowable (i.e. a level that provides efficient, reliable, safe, and complete combustion). The reduction in excess air typically reduces NOx emissions by 10% (in natural gas-fired units), reduces the total flue gas flow, and improves heat transfer.[52] With CEMS and feedback control, excess air can be accurately controlled to maintain a level

[50] Id.
[51] Id.
[52] Id.

that promotes optimum combustion and burning conditions in addition to lowering NOx emissions. Reducing excess air can also result in increased energy productivity (the amount of energy consumed per unit of production) which further reduces emissions.

Precise implementation of LEA is necessary to avoid incomplete combustion that may result in a decrease in energy efficiency, a decrease in steam temperature, and a significant increase in CO emissions. Without a strict control system, these characteristics can also lead to corrosion, opacity concerns, and even fires in air preheaters and ash hoppers (where applicable). One notable advantage of this strategy is that significant capital expenses for new or modified hardware are not required.

Staged Combustion

Staged combustion relies on the reduction of the peak flame zone temperature (and/or oxygen levels) to reduce NOx formation and is achieved by delaying or staging the addition of combustion air.

(d) Air Staging

Air staging can be carried out using overfire air (OFA) or two-stage combustion. With air staged combustion, the combustion air is controlled and distributed to create different combustion zones. The flame temperature is consequently reduced, which reduces the NOx created. In the first zone, the air is sparingly distributed to create an initial sub-stoichiometric fuel rich zone. In the second zone above the first, the air is generously introduced to complete the combustion in a high excess air, low temperature zone, reducing thermal NOx formation.

(e) Fuel Staging

Staged fuel combustion can be accomplished using burners out of service (BOOS), biasing the fuel flow to specific burners (a.k.a., biased firing), and fuel re-burning. These methods create different zones of fuel burning, such as fuel rich and fuel lean zones within the combustion unit by shutting off fuel flow, diverting fuel from specific burners, or by controlling air and fuel injection zones. Separating the combustion zones, reduces the flame temperature, thereby reducing NOx. BOOS and biasing the fuel flow to specific burners cannot be conducted on boilers with only one burner because these are techniques that use multi-burners. Staged fuel combustion can achieve up to 50% NOx reduction.

(f) Fuel Re-burn

Fuel re-burning is a staged fuel combustion technique where fuel is introduced downstream of the primary combustion chamber to create a secondary combustion zone. However, with fuel re-burning, the NOx formed in the primary combustion area is destroyed in the re-burn area. The additional fuel is often natural gas. Emission reductions of up to 60% are possible.[53]

Additions to Combustion Air or Fuel

Boiler operation can be optimized to reduce NOx emissions by injecting flue gases, water (or steam), oxygen, or other materials into the combustion zone or the fuel. This addition reduces NOx formation by altering the stoichiometric ratio of the combustion reactants. Typically, injected components (e.g. flue gas or steam) dilutes the combustion zone, reduces the temperature of the combustion zone, and reduces the formation of thermal NOx. When oxygen

[53] Id.

is added, it displaces an equivalent amount of air and therefore reduces the amount of nitrogen available for NOx formation.

(g) Water/Steam Injection (WSI)

As the name suggests, WSI involves the injection of water (or steam) into the primary combustion zone to reduce peak flame temperature and decrease NOx formation. More specifically, this process dilutes the combustion gas stream and functions as a heat sink; i.e. a portion of the available thermal energy is used to vaporize the water and raise the vaporized water temperature to the combustion temperature. WSI is a proven technology for oil-fired, coal-fired boilers, and combustion turbines, with a NOx reduction potential of up to 80% in natural gas-fired units.[54]

(h) Flue Gas Recirculation (FGR)

FGR is a technique in which a portion of the (inert) flue gas is recycled back to primary combustion zone. As a result, it reduces the formation of thermal NOx by lowering peak flame temperature and reducing the concentration of oxygen. FGR typically reduces emissions of NOx in a natural gas boiler by about 53 to 74%.[55]

Burner Replacement

(i) Low NOx Burners (LNB)

LNB is a unique pollution prevention control option in the sense that it simply refers to a burner that has been designed to emit less NOx than conventional burners. LNB are usually designed to incorporate one or more combustion control techniques within the burner, such as staged combustion, fuel/air premixing, flue gas recirculation, low excess air, or a combination of these techniques. In all cases, the NOx emissions are controlled by lowering combustion zone temperatures to reduce the production of thermal NOx. [56]

LNB is a relative term in the sense that is has evolved over time. For example, a 25-year old combustion unit "equipped with LNB" may have a NOx emission rate of approximately 50 ppm, while a new unit "equipped with LNB" may have a NOx emission rate of less than 30 ppm.[57] LNB technology is available from many manufacturers and applicable to all fuels. Low NOx burners typically achieve NOx reductions of 2 to 71 percent over conventional burners.[58]

Add-on Pollution Control Techniques

(j) Selective Catalytic Reduction (SCR)

SCR is an add-on control technique that controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. NH3, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH3 reacts with NOx to form molecular nitrogen and water. The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures can range from 350°F to 1,100°F but typically is designed to occur between 600°F and 750°F

[54] Id.
[55] Id.
[56] Id.
[57] Id.
[58] Id.

depending on the catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

(k) Selective Non-Catalytic Reduction (SNCR)

Like SCR, SNCR operates by promoting the conversion of NO_x into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires a flue gas of 1700-2000 °F.[59] Units with flue gas temperatures within this range, residence times less than one second, and high levels of uncontrolled NO_x are good candidates for SNCR control.[60]

Units can be retrofitted for SNCR by installing injection nozzles through holes cut in the furnace wall. The nozzles are connected by piping to air or steam and chemical supplies. Bulk chemical storage is normally remote from the individual heater and can be used for more than one heater or boiler. The SNCR systems require rapid chemical diffusion in the flue gas. The injection point must be selected to ensure adequate flue gas residence time and to avoid tube impingement. Computer modeling can be used to develop the optimum injection points.[61]

(l) Oxidant Injection with Absorption

This technique involves two stages. First, an oxidant (ozone or hydrogen peroxide) is injected and mixed into the exhaust of a combustion unit. NOx within the air flow is oxidized to its water-soluble higher valence states (e.g. NO_3). Second, a gas absorber is subsequently used to remove the water-soluble NOx from the gas stream. Water, hydrogen peroxide, or an alkaline fluid typically function as the absorbent.[62]

(m) Non Thermal Plasma Reactor

Ammonia, methane, or hexane may be used as reducing agents to react with NOx in exhaust gas within an electron beam generated plasma. Ionized reducing agents are created by a transient high voltage which reacts with NOx for a removal of greater than 94 percent.[63]

Fuel Switching

(n) Fuel Switching - Natural Gas

Fuel switching reduces NOx formation by reducing fuel NOx. By replacing high-nitrogen fuels with low-nitrogen fuels, the overall nitrogen available for oxidation is reduced, lowering NOx emissions. The primary fuel for the Clairton batteries COG. However, under rare circumstances, stabilized natural gas may be used as underfiring fuel.

<u>Step 2 – Eliminate Technically Infeasible Control Options</u>

Each control option listed in Step 1 was evaluated to determine if it represents a technically feasible means of controlling NOx emissions from Boiler 2. <u>In summary, it was determined that SCR and SNCR are technically feasible control options, the economic feasibility of which is evaluated in Step 3.</u>

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[59] Id.
[60] Id.
[61] Id.
[62] Id.
[63] Id.

(b)-(f) Various Types of Combustion Modifications and (i) Low NOx Burners

Boiler 2 is equipped with oxygen sensors that allow Clairton to closely control air-to-fuel ratios in the units. Results from stack testing indicates that the boilers are already operating at a low excess air rate; a form of NOx control.

A review of 2013 CEMS data Boiler 2 indicated that the boiler's average annual NOx emission rate is typically <50% of the permitted 0.54 lb/MMBtu NOx emission limit; a rate commonly associated with packaged natural gas-fired boilers equipped with LNB. Burner manufacturers have indicated (i.e. quoted) that replacement LNB would not reduce NOx emissions beyond what is currently being achieved by the boilers at Clairton. Therefore, LNBs considered infeasible.

Achieving further NOx reductions from combustion modifications is not expected to be feasible. A retrofit of boiler design would need to be modeled and analyzed using computer simulation to determine if NOx emission reductions could be achieved and to what extent. For this reason, combined with the existing NOx control measures, boiler consultants and vendors contacted by US Steel would not provide quotes for any form of combustion modifications or controls.

<u>As a result, additional combustion modifications, including the addition of LNB, are considered to be technically infeasible control options for reducing NOx emissions.</u>

(g) Water/Steam Injection

Water/steam injection (WSI) has been proven to reduce NOx emissions but does so with significant operational drawbacks, namely: reduced thermal efficiency, reduced steam production, and increased equipment corrosion. For these reasons, WSI has been primarily used on gas turbines where the reduction in thermal efficiency (and the resulting increase in fuel consumption) is much less than that which would be experienced by a steam boiler.

<u>WSI is considered to be a technically infeasible control option for reducing NOx emissions.</u>

(h) Flue Gas Recirculation (FGR)

Operation of Boiler 2 has been tuned for low excess air. Further suppression/reduction of air by any means would likely terminate the flame, and even the pilot, leading to incomplete combustion. If that scenario was to occur, VOC and opacity emissions would increase and likely result in permit violations.

<u>As a result, FGR is considered to be a technically infeasible control option for reducing NOx emissions.</u>

(n) Fuel switching

COG has already been determined to be the ideal primary fuel for each boiler at Clairton.

(l) – (m) Oxidant Injection with Absorption and Non-Thermal Plasma Reactor

There is no evidence that oxidant injection with absorption, or a non-thermal plasma reactor, has been successfully used with an industrial/commercial/institutional boiler, let alone a COG-fired boiler. <u>As a result, oxidant injection with absorption and non-thermal plasma reactor are considered to be undemonstrated technologies and technically infeasible control options for reducing NOx emissions.</u>

Step 3 - Evaluate Control Options

Periodic tune-ups, SCR, and SNCR have been determined to be technically feasible control options considering the exhaust characteristics of Boiler 2 and the demonstrated effectiveness of various technologies on other boiler systems. As a result, these options were evaluated further.

NOx emissions from Boiler 2 are limited to 0.54 lb/MMBtu, 259.74 lb/hr and 1,285 tons per twelve consecutive month period. The following table presents the estimated control efficiency and potential NOx reductions of the technically feasible control options.

Table 11 - Potential NOx Reductions from Technically Feasible Control Options for Boiler 2

Technically Feasible Control Option	Estimated Control Efficiency	Potential NOx Emissions Reductions (ton/yr)[64]	Estimated Post-control NOx emissions (lb/MMBtu)
Tune ups	2%	25.7	<0.54
SCR	90%	1,157	0.054
SNCR	45%	578	0.297

Using information provided by US Steel and collected by ACHD, a thorough economic analysis of SCR and SNCR was conducted - see Appendix A. The assessment for tune-ups is based on information provided in the following report: "USI Boiler Efficiency Program a Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities" (February, 2004).[65] The SCR and SNCR analyses consider the total costs associated with the NOx control equipment, including the total capital investment of the various components intrinsic to the complete system, the estimated annual operating costs, and indirect annual costs. All costs, and nearly all calculated values used to determine costs, were determined using the methodology described in the “EPA Air Pollution Control Cost Manual, Sixth Edition” (document # EPA 452-02-001) and other technical resources available in the EPA Clean Air Technology Center.

Calendar year 1998 data was the basis of the cost estimates and appropriately updated using the Chemical Engineering Plant Cost Index; an accepted approach for RACT/BACT/BART analyses. While other indices were considered such as the Consumer Price Index, Producers Price Index, the Chemical Engineering Plant Cost Index was the most comprehensive fit for the collection of equipment and structures covered by this analysis.

Since COG and blast furnace gas (BFG) are already fully used by the US Steel processes, fuel costs were based on the purchase of natural gas for any supplemental heat. Natural gas pricing was based on the U.S. Energy Information Administration and natural gas pricing for industrial users in Pennsylvania (latest available report). Electric costs were also based upon this reference. Cost figures were also supplemented by use of other published documents, such as the previously referenced Midwest States BART document for Iron and Steel Mills, as well as vendor provided information (where available). Certain items used in the analysis were based on site-specific or U.S. Steel specific information, such as the interest rate on capital, natural gas cost, ammonia costs and vendor quotes.

[64] Determined as the boiler allowable PTE (ton/yr) x Estimated control efficiency (%)
[65] Id.

Annualized costs are based on an interest rate of 7%, and an equipment life of 15 years. The basis of cost-effectiveness, used to evaluate control options, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost analysis is provided the following table:

Table 12. Economic Analysis of Technically Feasible Control Options for Boiler 2 [See Comment in Boiler 1 RACT.]

Technically Feasible Control Option	Total Capital Investment ($)	Total Annualized Cost ($/yr)	Potential NOx Removal (ton/yr)	Cost Effectiveness ($/ton NOx removed)
Tune ups	$6,500	$2,000	25.7	$80
SCR	$9,342,200	$6,244,400	1,157	$5,400
SNCR	$2,893,100	$16,665,200	578	$28,800

The large annualized cost for both SCR and SNCR is dominated by the significant increase in supplemental natural gas that would be consumed. The requisite fuel consumption is necessary to heat the boiler exhaust to the minimum SCR and SNCR operating temperatures.

With a calculated cost-effectiveness of more than $28,000 per ton of NOx removed, ACHD has determined that SNCR is not an economically feasible control option for Boiler 2. With a calculated cost-effectiveness of approximately $5,400 per ton of NOx removed, ACHD has determined that SCR is an economically feasible control option for Boiler 2.

Step 4 – Select RACT

ACHD has determined that NOx RACT for Boiler 2 is:

1. Installation of a SCR.
2. NOx emissions shall not exceed 133 tons per consecutive twelve month period and continued compliance with other permit conditions.
3. An annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize emissions of CO; and
- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

F. RACT for NOx – Boilers R1 (B005), R2 (B006), T1 (B007), and T2 (B008)

Process/Unit description – Boilers R1, R2, T1, and T2

Clairton uses a combination of six boilers to produce steam for various operations at the plant. Each boiler combusts COG as its primary fuel and natural gas as its secondary/backup fuel. Boilers R1, R2, T1, and T2 are packaged wall-fired-type units with heat input capacities of 229, 229, 156, and 156 MMBtu/hr, respectively. When either Boiler 1 or 2 are down, the four remaining boilers (R1, R2, T1, and T2) are operated to provide the required steam demands. Annual outages are planned during periods of lower steam demand (e.g. summer) so that less steam is required throughout the plant during annual outages; typically boilers R1, R2, and T1 operate near rated load and T2 is operated as a swing load.

Boilers R1 and R2 are identical. Boilers T1 and T2 are identical. Boilers R1/R2 and T1/T2 differ by design only in rated heat input capacity. As a result, the following RACT evaluation covers the four boilers collectively.

Pursuant to Conditions V.BB.1 and V.CC.1 of Clairton's Title V permit:

- NOx emissions from Boiler R1 are limited to 0.54 lb/MMBtu, 123.66 lb/hr, and 525 tons per twelve consecutive month period.
- NOx emissions from Boiler R2 are limited to 0.54 lb/MMBtu, 123.66 lb/hr, and 525 tons per twelve consecutive month period.
- NOx emissions from Boiler T1 are limited to 0.54 lb/MMBtu, 84.24 lb/hr, and 358 tons per twelve consecutive month period.
- NOx emissions from Boiler T2 are limited to 0.54 lb/MMBtu, 84.24 lb/hr, and 358 tons per twelve consecutive month period.
- Boilers R1, R2, T1, and T2 shall be properly maintained and operated according to good engineering and air pollution control practices at all times.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, NOx emissions from Boilers R1, R2, T1, and T2 could, in theory, be controlled with:

(a) Combustion Optimization
(b) Reduced Air Preheat
(c) Low Excess Air
(d) Staged Combustion - Air Staging
(e) Staged Combustion - Fuel Staging
(f) Fuel Re-burn
(g) Water/Steam Injection
(h) Flue Gas Recirculation
(i) Low NOx Burners
(j) Selective Catalytic Reduction
(k) Selective Non-Catalytic Reduction
(l) Oxidant Injection with Absorption
(m) Non Thermal Plasma Reactor
(n) Fuel Switching

These control measures have been organized into six categories: combustion optimization, staged combustion, additions to combustion air or fuel, burner replacement, post combustion controls, and fuel switching.

Pollution Prevention Techniques - Combustion Modifications

Boiler operation can be optimized to reduce NOx emissions by modifying boiler control settings. Sources can conduct a combustion optimization evaluation to determine the optimal settings for operating the boiler to address NOx emissions, as well as other factors. Alternatively, sources can specifically reduce the air preheat and/or the level of excess air to reduce NOx.

(a) Combustion Optimization

Combustion optimization involves conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms, and actuators) and determining if equipment needs to be cleaned or repaired. Also, combustion optimization includes conducting various tests to collect data on the boilers' operation. This data is then analyzed to determine the combination of settings that results in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

Tune-ups are used to improve efficiency and save money, reduce combustion emissions, and to ensure safe operations. A tune-up generally involves: conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, heat transfer surfaces, tilt mechanisms, and actuators); determining if equipment needs to be cleaned, repaired, or replaced; investigating levels of excess air and emissions of NOx and CO; evaluating temperatures and pressures; and inspecting for leakage and condensate. The data is analyzed and adjustments are made to determine the combination of settings that results in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

In a study by the North Carolina State University on the effect of tune-ups on state operated boilers[66], it was found that 1-5% fuel savings could be achieved. Although the effect on emissions was not reported, an emission decrease of 1-5% would have occurred based on the use of less fuel. However, additional NOx and CO emission reductions would be expected above those associated with efficiency improvements. It is difficult to predict the overall reduction in emissions that tune-ups can achieve because the pre-tune-up status is unknown.

(b) Reduced Air Preheat (RAP)

Boiler combustion air can be preheated using boiler exhaust to improve boiler efficiency. However, the technique can inherently increase NOx emissions because flame temperature is increased (relative to an identical boiler without preheating). Air preheaters are typically used on coal stoker grate water-tube boilers with a heat input capacity greater than 100 MMBtu/hr.[67]

RAP is a technique in which the primary combustion zone peak temperature is lowered by reducing the preheating of combustion air. One notable advantage of this strategy is that no significant capital expenses for new or modified hardware are required.

(c) Low Excess Air (LEA)

Controlling excess air used during fuel combustion can substantially affect NOx formation by determining the amount of oxygen available for NOx reaction. At a given excess air

[66] Id.
[67] Id.

level, NOx emissions increase as the temperature of the combustion zone increases. LEA is a burner optimization strategy in which the combustion unit is operated at the lowest excess air level allowable; i.e. a level that provides efficient, reliable, safe, and complete combustion. The reduction in excess air typically reduces NOx emissions by 10% (in natural gas-fired units), reduces the total flue gas flow, and improves heat transfer.[68] With CEMS and feedback control, excess air can be accurately controlled to maintain a level that promotes optimum combustion and burning conditions in addition to lowering NOx emissions. Reducing excess air can also result in increased energy productivity (the amount of energy consumed per unit of production) which further reduces emissions.

Precise implementation of LEA is necessary to avoid incomplete combustion, which may result in a decrease in energy efficiency, a decrease in steam temperature, and a significant increase in CO emissions. Without a strict control system, these characteristics can also lead to corrosion, opacity concerns, and even fires in air preheaters and ash hoppers (where applicable). One notable advantage of this strategy is that significant capital expenses for new or modified hardware are not required.

Staged Combustion

Staged combustion relies on the reduction of the peak flame zone temperature (and/or oxygen levels) to reduce NOx formation, and is achieved by delaying or staging the addition of combustion air.

(d) Air Staging

Air staging can be carried out using overfire air (OFA) or two-stage combustion. With air staged combustion, the combustion air is controlled and distributed to create different combustion zones. The flame temperature is consequently reduced, which reduces the NOx created. In the first zone, the air is sparingly distributed to create an initial sub-stoichiometric fuel rich zone. In the second zone above the first, the air is generously introduced to complete the combustion in a high excess air, low temperature zone, reducing thermal NOx formation.

(e) Fuel Staging

Staged fuel combustion can be accomplished using burners out of service (BOOS), biasing the fuel flow to specific burners (a.k.a., biased firing), and fuel re-burning. These methods create different zones of fuel burning, such as fuel rich and fuel lean zones, within the combustion unit by shutting off fuel flow, diverting fuel from specific burners, or by controlling air and fuel injection zones. Separating the combustion zones reduces the flame temperature, thereby reducing NOx. BOOS and biasing the fuel flow to specific burners cannot be conducted on boilers with only one burner because these are techniques that use multi-burners. Staged fuel combustion can achieve up to 50% NOx reduction.

(f) Fuel Re-burn

Fuel re-burning is a staged fuel combustion technique where fuel is introduced downstream of the primary combustion chamber to create a secondary combustion zone. However, with fuel re-burning, the NOx formed in the primary combustion area is destroyed in the re-burn area. The additional fuel is often natural gas. Emission reductions of up to 60% are possible.[69]

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[68] Id.
[69] Id.

Additions to Combustion Air or Fuel

Boiler operation can be optimized to reduce NOx emissions by injecting flue gases, water (or steam), oxygen, or other materials into the combustion zone or the fuel. This addition reduces NOx formation by altering the stoichiometric ratio of the combustion reactants. Typically, injected components (e.g. flue gas or steam) dilutes the combustion zone and reduces the temperature of the combustion zone, and reduces the formation of thermal NOx. When oxygen is added, it displaces an equivalent amount of air and therefore reduces the amount of nitrogen available for NOx formation.

(g) Water/Steam Injection (WSI)

As the name suggests, WSI involves the injection of water (or steam) into the primary combustion zone to reduce peak flame temperature and decrease NOx formation. More specifically, this process dilutes the combustion gas stream and functions as a heat sink; i.e. a portion of the available thermal energy is used to vaporize the water and raise the vaporized water temperature to the combustion temperature. WSI is a proven technology for oil-fired, coal-fired boilers, and combustion turbines, with a NOx reduction potential of up to 80% in natural gas-fired units.[70]

(h) Flue Gas Recirculation (FGR)

FGR is a technique in which a portion of the (inert) flue gas is recycled back to primary combustion zone. As a result, it reduces the formation of thermal NOx by lowering peak flame temperature and reducing the concentration of oxygen. FGR typically reduces emissions of NOx in a natural gas boiler by about 53 to 74%.[71]

Burner Replacement

(i) Low NOx Burners (LNB)

LNB is a unique pollution prevention control option in the sense that it simply refers to a burner that has been designed to emit less NOx than conventional burners. LNB are usually designed to incorporate one or more combustion control techniques within the burner such as staged combustion, fuel/air premixing, flue gas recirculation, low excess air, or a combination of these techniques. In all cases, the NOx emissions are controlled by lowering combustion zone temperatures to reduce the production of thermal NOx. [72]

LNB is a relative term in the sense that is has evolved over time. For example, a 25-year old combustion unit "equipped with LNB" may have a NOx emission rate of approximately 50 ppm while a new unit "equipped with LNB" may have a NOx emission rate of less than 30 ppm.[73] LNB technology is available from many manufacturers and applicable to all fuels. Low NOx burners typically achieve NOx reductions of 2 to 71 percent over conventional burners.[74]

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[70] Id.
[71] Id.
[72] Id.
[73] Id.
[74] Id.

Add-on Pollution Control Techniques

(j) Selective Catalytic Reduction (SCR)

SCR is an add-on control technique that controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. NH3, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH3 reacts with NOx to form molecular nitrogen and water. The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures can range from 350°F to 1,100°F but typically is designed to occur between 600°F and 750°F, depending on the catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

(k) Selective Non-Catalytic Reduction (SNCR)

Like SCR, SNCR operates by promoting the conversion of NO_x into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires a flue gas of 1700-2000 °F.[75] Units with flue gas temperatures within this range, residence times less than one second, and high levels of uncontrolled NO_x are good candidates for SNCR control.[76]

Units can be retrofitted for SNCR by installing injection nozzles through holes cut in the furnace wall. The nozzles are connected by piping to air or steam and chemical supplies. Bulk chemical storage is normally remote from the individual heater and can be used for more than one heater or boiler. The SNCR systems require rapid chemical diffusion in the flue gas. The injection point must be selected to ensure adequate flue gas residence time and to avoid tube impingement. Computer modeling can be used to develop the optimum injection points.[77]

(l) Oxidant Injection with Absorption

This technique involves two stages. First, an oxidant (ozone or hydrogen peroxide) is injected and mixed into the exhaust of a combustion unit. NOx within the air flow is oxidized to its water-soluble higher valence states (e.g. NO_3). Second, a gas absorber is subsequently used to remove the water-soluble NOx from the gas stream. Water, hydrogen peroxide, or an alkaline fluid typically function as the absorbant.[78]

(m) Non Thermal Plasma Reactor

Ammonia, methane, or hexane may be used as reducing agents to react with NOx in exhaust gas within an electron beam generated plasma. Ionized reducing agents are created by a transient high voltage which reacts with NOx for a removal of greater than 94 percent.[79]

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[75] Id.
[76] Id.
[77] Id.
[78] Id.
[79] Id.

Fuel Switching

(n) Fuel Switching - Natural Gas

Fuel switching reduces NOx formation by reducing fuel NOx. By replacing high-nitrogen fuels with low-nitrogen fuels, the overall nitrogen available for oxidation is reduced, lowering NOx emissions. The primary fuel for the Clairton batteries is COG. However, under rare circumstances, stabilized natural gas may be used as underfiring fuel.

Step 2 – Eliminate Technically Infeasible Control Options

Each control option listed in Step 1 was evaluated to determine if it represents a technically feasible means of controlling NOx emissions from Boilers R1, R2, T1, and T2. In summary, it was determined that SCR and SNCR are technically feasible control options, the economic feasibility of which is evaluated in Step 3.

(b)-(f) Various Types of Combustion Modifications and (i) Low NOx Burners

Boilers R1, R2, T1 and T2 are equipped with oxygen sensors that allow Clairton to closely control air-to-fuel ratios in the units. Results from stack testing indicates that the boilers are already operating at a low excess air rate; a form of NOx control.

Recent stack tests for boilers R1, R2, T1, and T2 indicate that the NOx emission rates for the units range from 0.13 to 0.20 lb/MMBtu; rates commonly associated with packaged natural gas-fired boilers equipped with LNB. Burner manufacturers have indicated (i.e. quoted) that replacement LNB would not reduce NOx emissions beyond what is currently being achieved by the boilers at Clairton (Therefore, LNBs are listed here as technically infeasible.

Achieving further NOx reductions from combustion modifications or boiler tuning are not expected to be feasible. A retrofit of boiler design would need to be modeled and analyzed using computer simulation to determine if NOx emission reductions could be achieved and to what extent. For this reason, combined with the existing NOx control measures, boiler consultants and vendors contacted by US Steel would not provide quotes for any form of combustion modifications or controls.

As a result, additional combustion modifications (including the addition of LNB) are considered to be technically infeasible control options for reducing NOx emissions.

(g) Water/Steam Injection

Water/steam injection (WSI) has been proven to reduce NOx emissions but does so with significant operational drawbacks, namely: reduced thermal efficiency, reduced steam production, and increased equipment corrosion. For these reasons, WSI has been primarily used on gas turbines where the reduction in thermal efficiency (and the resulting increase in fuel consumption) is much less than that which would be experienced by a steam boiler.

WSI is considered to be a technically infeasible control option for reducing NOx emissions.

(h) Flue Gas Recirculation (FGR)

Operation of each boiler (R1, R2, T1, and T2) has been tuned for low excess air to reduce NOx emissions. Further suppression/reduction of air by any means would likely terminate

the flame, and even the pilot, leading to incomplete combustion. If that scenario was to occur, VOC and opacity emissions would increase and likely result in permit violations.

As a result, FGR is considered to be a technically infeasible control option for reducing NOx emissions.

(n) Fuel switching

COG has already been determined to be the ideal primary fuel for each boiler at Clairton.

(l) – (m) Oxidant Injection with Absorption and Non-Thermal Plasma Reactor

There is no evidence that oxidant injection with absorption, or a non-thermal plasma reactor, has been successfully used with an industrial/commercial/institutional boiler, let alone a COG-fired boiler. As a result, oxidant injection with absorption and non-thermal plasma reactor are considered to be undemonstrated technologies and technically infeasible control options for reducing NOx emissions.

Step 3 - Evaluate Control Options

Periodic tune-ups, SCR, and SNCR have been determined to be technically feasible control options considering the exhaust characteristics of the boilers (R1, R2, T1, and T2) and the demonstrated effectiveness of various technologies on other boiler systems. As a result, these control options were evaluated further.

The following table presents the estimated control efficiency and potential NOx reductions of the technically feasible control options.

Table 13 - Potential NOx Reductions from Technically Feasible Control Options for Boilers R1, R2, T1 and T2

Technically Feasible Control Option	Estimated Control Efficiency	Potential NOx Emissions Reductions (ton/yr)[80]	Estimated Post-control NOx emissions (lb/MMBtu)[a]
Boilers R1 and R2 (figures are per boiler)			
Tune ups	2%	10.5	<0.54
SCR	90%	473	0.054
SNCR	45%	236	0.297
Boilers T1 and T2 (figures are per boiler)			
Tune ups	2%	7.2	<0.54
SCR	90%	322	0.054
SNCR	45%	161	0.297

[a] Using permit lb/hr * (100%-control efficiency %)/capacity in MMBTU/hr

Using information provided by US Steel and collected by ACHD, a thorough economic analysis of SCR and SNCR was conducted - see Appendix A. The assessment for tune-ups is based on information provided in the following report: "USI Boiler Efficiency Program a Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated

[80] Determined as the boiler allowable PTE (ton/yr) x Estimated control efficiency (%)

Facilities" February, 2004.[81] The SCR and SNCR analyses consider the total costs associated with the NOx control equipment, including the total capital investment of the various components intrinsic to the complete system, the estimated annual operating costs, and indirect annual costs. All costs, and nearly all calculated values used to determine costs, were determined using the methodology described in the "EPA Air Pollution Control Cost Manual, Sixth Edition" (document # EPA 452-02-001) and other technical resources available in the EPA Clean Air Technology Center.

Calendar year 1998 data was used as the basis of the cost estimates and appropriately updated using the Chemical Engineering Plant Cost Index; an accepted approach for RACT/BACT/BART analyses. While other indices were considered, such as the Consumer Price Index, Producers Price Index, the Chemical Engineering Plant Cost Index was the most comprehensive fit for the collection of equipment and structures covered by this analysis.

Since COG and blast furnace gas (BFG) are already fully used by the US Steel processes, fuel costs were based on the purchase of natural gas for any supplemental heat. Natural gas pricing was based on the U.S. Energy Information Administration, natural gas pricing for industrial users in Pennsylvania (latest available report). Electric costs were also based upon this reference. Cost figures were also supplemented by use of other published documents, such as the previously referenced Midwest States BART document for Iron and Steel Mills, as well as vendor provided information (where available). Certain items used in the analysis were based on site-specific or U.S. Steel specific information, such as the interest rate on capital, natural gas cost, ammonia costs and vendor quotes.

Annualized costs are based on an interest rate of 7% and an equipment life of 15 years. The basis of cost-effectiveness, used to evaluate control options, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost analysis is provided the following table:

Table 14. Economic Analysis of Technically Feasible Control Options for Boilers T1, T2, R1 and R2 [See Comment in Boiler 1 RACT].

Technically Feasible Control Option	Total Capital Investment ($)	Total Annualized Cost ($/yr)	Potential NOx Removal (ton/yr)	Cost Effectiveness ($/ton NOx removed)
Boilers R1 and R2 (figures are per boiler)				
Tune ups	$6,500	$2,000	10.5	$200
SCR	$4,764,000	$2,475,800	473	$5,200
SNCR	$2,015,500	$5,788,400	236	$24,500
Boilers T1 and T2 (figures are per boiler)				
Tune ups	$6,500	$2,000	7.2	$300
SCR	$4,210,600	$1,931,300	322	$6,000
SNCR	$1,682,500	$4,441,600	161	$27,600

The large annualized cost for SNCR is dominated by the significant increase in supplemental natural gas that would be consumed. This requisite fuel consumption is necessary to heat the boiler exhaust to the minimum SCR and SNCR operating temperatures.

[81] Id.

With a calculated cost-effectiveness of more than $24,000 per ton of NOx removed, ACHD has determined that SNCR is not an economically feasible control option for Boilers R1, R2, T1 and T2. With a calculated cost-effectiveness of $5,200 per ton of NOx removed, ACHD has determined that SCR is an economically feasible control option for Boilers R1 and R2. With a calculated cost-effectiveness of $6,000 per ton of NOx removed, ACHD has determined that SCR is not an economically feasible control option for Boilers T1 and T2.

Step 4 – Select RACT

ACHD has determined that NOx RACT for Boilers R1, R2, T1, and T2 is:

1. Installation of SCR on boilers R1 and R2. NOx emissions for each boiler shall not exceed 54 tons per consecutive twelve month period. Continued compliance with other permit conditions.
2. Boilers T1 and T2 continue to comply with current permit conditions.
3. An annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize emissions of CO; and
- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

G. RACT for VOC – Underfiring of Coke Batteries B, 1, 2, 3, 13, 14, 15, 19, and 20

Process/Unit description – Underfiring

Clairton currently operates ten by-product coke oven batteries, each consisting of 64 to 87 ovens, identified as Batteries C, B, 1, 2, 3, 13, 14, 15, 19, and 20. (As explained previously in this document, Battery C is not addressed further.)

The coking process begins with the transfer, i.e. "charge", of coal through an opening in the top of the oven. Once the oven has been filled with coal and sealed, the oven is uniformly heated. Heat is produced from the combustion of COG in one-half of the flues (a process referred to as "underfiring") while the remaining flues transport combustion exhaust gas through a heat exchanger (called a regenerator). (Flues are located within the walls of the each coke oven. Regenerators are massive structures made of refractory brick and are located beneath the ovens and heating flues.) Underfiring exhaust gases leaving the regenerators are routed to, and ultimately emitted from, a "combustion stack". Each coking cycle typically takes between 16 to 18 hours.

In addition to producing coke, a by-product coke battery is designed and operated to collect the COG evolved from coal during the coking process. The COG escapes through an opening at the top of the oven at both ends of the coking chamber. Each opening is fitted with an offtake pipe, which routes the COG to the collection main for processing. VOC emissions from underfiring are primarily the result of incomplete COG combustion.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, EPA's CTG document for Volatile Organic Emissions from Stationary Sources [82], EPA's "Control Technologies for Hazardous Air Pollutants",[83] VOC emissions from coke battery underfiring could, in theory, be controlled with:

(a) Thermal Oxidation
(b) Carbon Adsorption
(c) Condensation
(d) Routing to a Boiler
(e) Routing to a Flare
(f) Combustion/Performance Optimization

A concise description of each of these technologies is as follows:

(a) Thermal Oxidation (TO)

Thermal oxidizers are refractory lined enclosures with one or more burners in which the waste gas stream is routed through a high temperature combustion zone where it is heated and the combustible materials are burned. Thermal oxidizers typically operate at 1200 to 2100° Fahrenheit with residence times typically ranging from 0.5 to

[82] Control Techniques Guidelines Document – Control Techniques for Volatile Organic Emissions from Stationary Sources (EPA-450/R-78-022). Available at: http://www.epa.gov/airquality/ozonepollution/SIPToolkit/ctg_act/197805_voc_epa450_2-78-022_stationary_sources.pdf. Accessed January 28, 2015.
[83] Control Technologies for Hazardous Air Pollutants, EPA 625/6-86/014, September 1986. Available at: http://nepis.epa.gov/Adobe/PDF/20013494.PDF. Accessed January 28, 2015.

2 seconds. An efficient thermal oxidizer design must provide adequate residence time for complete combustion, sufficiently high temperatures for VOC destruction, and adequate velocities to ensure proper mixing without quenching combustion. The type of burners and their arrangement affect combustion rates and residence time; the more thorough the contact between the flame and VOC, the shorter the time required for complete combustion. Natural gas is required to ignite the flue gas mixtures and maintain combustion temperatures. Typically, a heat exchanger upstream of the oxidizer uses the heat content of the oxidizer flue gas to preheat the incoming VOC-laden stream to improve the efficiency of the oxidizer. Regenerative thermal oxidation uses a ceramic bed to transfer recovered heat from the high-temperature oxidized gases to the low-temperature polluted stream. This form of oxidation achieves higher destruction efficiencies and greater fuel economy than traditional 'straight' thermal oxidation. Thermal oxidizers can achieve a wide range of efficiencies, and usually achieve organic vapor removal efficiencies in excess of 95 percent.[84]

(b) Carbon Adsorption

Carbon adsorption is a process by which VOC is retained on a granular carbon surface, which is highly porous and has a very large surface-to-volume ratio. Organic vapors retained on the adsorbent are thereafter desorbed and both the adsorbate and absorbent are recovered. Carbon adsorption systems operated in two phases: adsorption and desorption. Adsorption is rapid and removes most of the VOC in the stream. Eventually, the adsorbent becomes saturated with the vapors and the system's efficiency drops. Regulatory considerations dictate that the adsorbent be regenerated or replaced soon after efficiency begins to decline. In regenerative systems, the adsorbent is reactivated with steam or hot air and the absorbate (solvent) is recovered for reuse or disposal. Non-regenerative systems require the removal of the adsorbent and replacement with fresh or previously regenerated carbon. Removal efficiencies of 95 to 99 percent can be achieved using carbon adsorption.[85] The effectiveness of carbon adsorption is largely dependent on available carbon sites.

(c) Condensation

Condensation is a process in which a phase change (gaseous to liquid) is induced to remove VOCs from the emission stream. The condensed organic vapors can be recovered, refined, and might be reused, preventing their release to the ambient air. There are two ways to obtain condensation. First, at a given temperature, the system pressure may be increased until the partial pressure of the condensable components equals its vapor pressure. Alternately, at a fixed pressure, the temperature of the gaseous mixture may be reduced until the vapor pressure of the condensable component equals its partial pressure. In practice, condensation is achieved mainly through the latter, with removal of heat from the vapor. Condensation is usually applied in combination with other air pollution control systems. Condensers are often located upstream of afterburners, carbon beds, or absorbers to reduce the total load entering the control equipment. When used alone, a refrigerated condenser works best on emission streams containing high concentrations of VOCs. A refrigerated condenser works best in situations where the air stream is saturated with the organic compound, the organic vapor containment system limits air flow, and the required air flow does not overload a refrigeration system with heat. The removal efficiency of a refrigerated

[84] Control Techniques Guidelines Document – Control Techniques for Volatile Organic Emissions from Stationary Sources (EPA-450/R-78-022). Available at: http://www.epa.gov/airquality/ozonepollution/SIPToolkit/ctg_act/197805_voc_epa450_2-78-022_stationary_sources.pdf. Accessed January 2015.

[85] Carbon Adsorption for Control of VOC Emissions: Theory and Full Scale System Performance (EPA-450/3-88-012). Available at: http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=91009Z7B.txt. Accessed February 2015.

condenser is directly related to the lowest temperature that can be achieved in the condenser. Removal efficiencies depend on the hydrocarbon concentration of the inlet vapors but are greater than 96% for the removal of saturated VOC.

(d) Routing to Boiler

Fireboxes of boilers can be potential afterburners for control of VOC if the temperature, turbulence, and flame contact are adequate to burn the combustible contaminant. Typically, emission streams are controlled in boilers or process heaters and used as supplemental fuel only if they have sufficient heating value (greater than 150 Btu/scf). If the waste VOC has appreciable heating value, the firebox must be specially designed to take advantage of the heat potential. When used as emission control devices, boilers or process heaters can provide destruction efficiencies of greater than 95 percent at little cost.[86]

There are some limitations in the application of boilers as emission control devices. Since these units are intended to provide heat or steam that is essential to process operations, they can only be used to control those emission streams that will not reduce their performance or reliability. Variations in stream flow rate and/or heating value, or the presence of corrosive compounds in the emission stream, could adversely affect the performance of a boiler or process heater.

(e) Routing to a Flare

Flares are typically applied when the heating value of the waste gases cannot be recovered economically because of intermittent or uncertain flow, or when process upsets occur. In general, flare performance depends on factors such as flare gas velocity, emission stream heating value, residence time in the combustion zone, waste gas/oxygen mixing, and flame temperature. If conditions in the flame zone are optimal, a non-assisted flare may achieve a VOC destruction efficiency of 98 percent or greater.[87] It may be necessary to add supplementary fuel to the emission stream to achieve this destruction efficiency if the net heating value of the emission stream is less than 300 Btu/scf. For assisted flares such as steam-assisted or air-assisted units, combustion efficiencies may be lower.

Flares are usually unsuitable for the treatment of dilute gas streams because the costs of supplemental fuel needed to attain the minimum combustion temperature are prohibitive. Unlike afterburners, flares have no heat recovery capability that could produce credits for heat generated from combustion. Flares are also generally less effective than other devices in controlling organic vapors.[88]

(f) Combustion/Performance Optimization

Operating and maintenance (O&M) practices have a significant impact on combustion unit performance, including VOC emissions, reliability, and operating costs. Each of these parameters change over the life of the unit, and some deterioration of equipment is unavoidable. VOC emissions can be minimized by adjusting the fuel to air ratio and burner configuration for optimum fuel combustion. (For facilities with NOx limitations, these adjustments may also consider minimization of NOx emissions.) Routine inspection, maintenance, and tuning extends the life of the equipment and ensures the equipment is performing optimally. In general, an annual tune-up includes:

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[86] *Id.*
[87] *Id.*
[88] *Id*.

- Inspection of the burner(s), and cleaning or replacement of any components of the burner(s) as necessary;
- Inspection of the flame pattern, as applicable, and adjustment of the burner(s) as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
- Inspection of the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly; and
- Optimization of total emissions of CO, which is used as surrogate for combustion efficiency. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject.

An energy efficiency assessment (aka energy efficiency audit) typically serves as the foundation for combustion unit efficiency improvements by providing an evaluation of actual performance relative to its design and potential. Every cubic foot of fuel saved from the implementation of one or more efficiency improvements directly results in reduced emissions. An energy assessment is performed by a qualified energy assessor and generally includes:

- A visual inspection of the system.
- An evaluation of operating characteristics, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.

An energy assessment provides valuable information on improving energy efficiency. The Department of Energy (DOE) conducted energy assessments at selected manufacturing facilities and determined that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices serve as pollution prevention measures because they reduce the amount of fuel combusted which directly translates to emissions reductions.[89]

Step 2 – Eliminate Technically Infeasible Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, there are no technically feasible control options for further reducing VOC emissions from coke battery underfiring. This determination is based on the following information:

- From a pollution prevention standpoint, the VOC emissions from underfiring process are minimized through compliance with the requirements of 40 CFR Part 63, Subpart CCCCC (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coke Ovens: Pushing, Quenching and Battery Stacks). The provisions of the NESHAP finalized in 2003 and last amended in August 2006 to which Clairton is subject, constitute Maximum Achievable Control Technology (MACT). By definition, MACT - while designed to reduce volatile HAPs (which includes organic compounds and VOC) in this case is at least as stringent as RACT.

- As a fuel combustion process, the underfiring of Coke Battery No. 1 produces a high volumetric exhaust flow rate relative to the amount of VOC emitted. The corresponding VOC concentration in the stack exhaust is too low for any form of add-on VOC control to be suitable. A review of the RBLC (Process Codes 81.112 and 81.190) substantiates this fact; add-on VOC controls have not been applied to coke battery underfiring.

[89] From proposed National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers. (75 FR 31907, June 4, 2010).

Step 3 - Evaluate Control Options

Not applicable.

Step 4 – Select RACT

ACHD has determined that VOC RACT for the underfiring of Batteries B, 1, 2, 3, 13, 14, 15, 19, and 20 is the current requirements established by Clairton's Title V permit. More specifically, Clairton must comply with the applicable requirements of 40 CFR Part 63, Subpart CCCCC.

H. RACT for VOC – By-Products Recovery Plant

Process/Unit description – By-Products Recovery Plant

Large quantities of raw COG, approximately 225 million cubic feet per day, are produced in the Clairton coke battery ovens. The evolved COG exits the battery ovens through standpipes, is spray-cooled to precipitate tar and condense various vapors and routed to the collection main. The collected COG is routed to the By-Products Recovery Plant (BPRP), where a variety of valuable organic compounds are extracted.

According to the Technical Support Document to Clairton's Title V permit:

> COG is 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. The daily production of these by-products includes approximately 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 50 tons of anhydrous ammonia, and 35 tons of elemental sulfur (produced in the Desulfurization Plant). Emissions of volatile organics from storage tanks and other equipment in the BPRP 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 aggregated coke oven gas is used as fuel for boilers, furnaces and other fuel burning equipment at the Clairton Works and the Irvin and Edgar Thomson Plants.
>
> The BPRP (identified as permitted process P021) consists of the following number and type of equipment: main axial compressors, main regenerators, main vacuum machines, light oil vacuum machines, 8-light oil condensers, 3-cooler separators, light oil regenerators, 3-light oil tanks, final cooler demister wash, super-still light oil decanter, light oil blow down tank, 2-light oil decanters (V-604 & 605), 6-light oil storage tanks (T59 – T64), 9-tar storage tanks (3TA 41-49), 22-tar Decanters (3TA 12-23, 25-28, & 30-35), 3-wastewater surge tanks, 2-wastewater settling tanks, wastewater ammonia still feed tank, methanol storage tank–V-400 (50,000 gallons), foul methanol storage tank-V-410 (50,000 gallons), and methanol/MEA storage tank-V430 (20,000 gallons).

The BPRP gas blanketing system has an estimated VOC control efficiency of 98 percent and is used to comply with the requirements of 40 CFR Part 61, Subpart L.

Pursuant to Clairton's Title V permit, VOC RACT for the BPRP is currently proper operation and maintenance of the plant in accordance with good engineering and air pollution control practices.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, VOC emissions from the entire BPRP could, in theory, be controlled with:

(a) Thermal Oxidization
(b) Carbon Adsorption
(c) Catalytic Oxidization
(d) Refrigerated Condensation
(e) Flaring
(f) Leak Detection and Repair (LDAR) program

A concise description of each of these technologies is as follows:

(a) Thermal Oxidation

Thermal oxidizers are refractory lined enclosures with one or more burners in which the waste gas stream is routed through a high temperature combustion zone where it is heated and the combustible materials are burned. Thermal oxidizers typically operate at 1200 to 2100 degrees Fahrenheit with residence times typically ranging from 0.5 to 2 seconds. An efficient thermal oxidizer design must provide adequate residence time for complete combustion, sufficiently high temperatures for VOC destruction, and adequate velocities to ensure proper mixing without quenching combustion. The type of burners and their arrangement affect combustion rates and residence time; the more thorough the contact between the flame and VOC, the shorter the time required for complete combustion. Natural gas is required to ignite the flue gas mixtures and maintain combustion temperatures. Typically, a heat exchanger upstream of the oxidizer uses the heat content of the oxidizer flue gas to preheat the incoming VOC-laden stream to improve the efficiency of the oxidizer. Thermal oxidizers can achieve a wide range of efficiencies and usually achieve VOC vapor removal efficiencies in excess of 95 percent.[90]

Thermal Oxidation can be used over a fairly wide range of organic vapor concentrations. However, concentration of the organics in the waste gas must be substantially below the lower explosive limit of the compound being controlled. Accounting for economic factors, thermal oxidation performs best at inlet concentrations from approximately 1500 to 3000 ppmv, because the heat of combustion of the hydrocarbon gases is sufficient to sustain the requisite temperature. Otherwise, the emissions reductions benefit of the oxidizer is somewhat offset by the emissions created by the supplemental fuel required. While air stream pretreatment is generally not required, thermal oxidation is generally not recommended for controlling gas streams containing halogen (or sulfur) containing compounds because of the resulting formation of corrosive gases (e.g. hydrogen chloride) and/or SO2.[91]

(b) Carbon Adsorption

Carbon adsorption is a process by which VOC is retained on a granular carbon surface (the adsorbent), which is highly porous and has a very large surface-to-volume ratio. Eventually, the adsorbent becomes saturated with the vapors and the system's efficiency drops. Regulatory considerations dictate that the adsorbent be regenerated or replaced soon after efficiency begins to decline. Compounds with high molecular weights greater than 50 and a boiling point greater than 50 degrees C are typically good candidates for adsorption. In regenerative systems, carbon adsorption systems operated in two phases: adsorption and desorption. Adsorption is rapid and removes most of the VOC in the stream. Desorption is the process by which the adsorbent is reactivated (typically with

[90] Control Techniques Guidelines Document – Control Techniques for Volatile Organic Emissions from Stationary Sources (EPA-450/R-78-022). Available at: http://www.epa.gov/airquality/ozonepollution/SIPToolkit/ctg_act/197805_voc_epa450_2-78-022_stationary_sources.pdf. Accessed January, 2015.
[91] Air Pollution Control Technology Fact Sheet - Thermal Incinerator (EPA-452/F-03-022). Available at http://www.epa.gov/ttn/catc/dir1/fthermal.pdf. Accessed January, 2015.

steam or hot air) and an absorbate (a solvent appropriate for the VOC) is used to collect the retained VOC. The absorbate is then recovered for reuse or disposal. VOC compounds that are difficult to desorb from the carbon media will significantly reduce VOC control effectiveness. In non-regenerative systems, the adsorbent is simply removed and replaced with fresh or previously regenerated carbon. Removal efficiencies of 90 to 99 percent can be achieved using carbon adsorption.[92]

(c) Catalytic Oxidation

Catalytic oxidizers are similar to thermal oxidizers in that the units are enclosed structures that use heat to oxidize the combustible materials. However, in a catalytic oxidizer, a catalyst is used to lower the operating temperature needed to oxidize the VOCs by lowering the activation energy for oxidation. When a preheated gas stream is passed through a catalytic oxidizer, the catalyst bed initiates and promotes the oxidation of the VOC without being permanently altered itself. Note that steps must be taken to ensure complete combustion. The types of catalysts used include platinum, platinum alloys, copper chromate, copper oxide, chromium, manganese, and nickel. These catalysts are deposited in thin layers on an inert substrate (usually a honeycomb shaped ceramic). VOC destruction efficiency is dependent upon a number of factors, including VOC composition and concentration, operating temperature, and the velocity of the gas passing through the bed. As the velocity increases, VOC destruction efficiency decreases. As temperature increases, VOC destruction efficiency increases. Catalytic oxidation is therefore most suited for air streams with low exhaust volumes, with little variation in the type and concentration of VOC, and where catalyst poisons or other fouling containments (e.g. silicone, sulfur, particulates etc.) are not present. Catalytic oxidation has been used effectively with very low VOC inlet loadings (around 1 ppmv). As with other types of incinerators, concentration of the organics in the waste gas must be substantially below the lower explosive limit of the compound being controlled. Catalytic oxidizers typically achieve greater than or equal to 98% VOC reduction.[93]

(d) Refrigerated Condensation

A refrigerated condenser is a control device that is used to cool an emission stream having organic vapors in it and to change the vapors to a liquid. The condensed organic vapors can be recovered, refined, and might be reused, preventing their release to the ambient air. A refrigerated condenser works best on emission streams containing high concentrations of VOC. A refrigerated condenser works best in situations where the air stream is saturated with the organic compound, the organic vapor containment system limits air flow, and the required air flow does not overload a refrigeration system with heat. The removal efficiency of a condenser is directly related to the lowest temperature that can be achieved in the condenser. Condensation is feasible for air streams with a high VOC concentration of few organic compounds. The greater the number of VOC components, the lower the temperature that must be maintained to achieve effective condensation. Removal efficiencies typically range from 50-98%.[94]

(e) Flaring

Flaring is an open-air combustion process typically applied when the heating value of the air stream cannot be recovered economically because of intermittent or uncertain flow, or

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[92] Carbon Adsorption for Control of VOC Emissions: Theory and Full Scale System Performance (EPA-450/3-88-012). Available at: http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=91009Z7B.txt. Accessed February, 2015.
[93] Air Pollution Control Technology Fact Sheet - Catalytic Incinerator (EPA-452/F-03-018). Available at http://www.epa.gov/ttn/catc/dir1/fcataly.pdf. Accessed January, 2015.
[94] Air Pollution Control Technology Fact Sheet - Refrigerated Condensers for Control of Organic Air Emissions (EPA-456/R-01-004). Available at http://www.epa.gov/ttn/catc/dir1/refrigeratedcondensers.pdf. Accessed January, 2015.

when process upsets occur. In general, flare performance depends on a number of factors, including gas velocity, emission stream heating value, residence time in the combustion zone, waste gas/oxygen mixing, and flame temperature. If conditions in the flame zone are optimal, a non-assisted flare may achieve a VOC destruction efficiency of 98 percent or greater. It may be necessary to add supplementary fuel to the emission stream to achieve this destruction efficiency if the net heating value of the emission stream is less than 300 Btu/scf. For assisted flares such as steam-assisted or air-assisted units, combustion efficiencies may be lower.

Flares are typically unsuitable for the treatment of dilute gas streams because the costs of supplemental fuel needed to attain the minimum combustion temperature are prohibitive. Unlike afterburners, flares have no heat recovery capability that could produce credits for heat generated from combustion. Flares are also generally less effective than other devices in controlling organic vapors.[95]

(f) Leak Detection and Repair (LDAR) Program

A LDAR program is a work practice designed to identify leaking equipment so that emissions can be reduced through repairs. A component that is subject to LDAR requirements must be monitored at specified regular intervals to determine whether or not it is leaking. Any leaking component must then be repaired or replaced within a specified time frame. Emissions reductions from implementing an LDAR program potentially reduce product losses, increase safety for workers and operators, decrease exposure of the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. In general, elements of an LDAR program include the identification of components, leak detection activities, monitoring, repair, and recordkeeping. LDAR programs are required by many federal, state, and local regulations.[96]

Step 2 – Eliminate Technically Infeasible Control Options

VOC emissions from the BPRP are mostly fugitive in nature and are emitted in insignificant-to-small quantities from a very large number of emission points. The estimated VOC PTE of the various equipment encompassed by the BPRP (including VOC-containing storage tanks) is 124 ton/yr. [This is from the 2014 US Steel Clairton RACT submittal. This is comparable to the 121 tpy shown in the TVOP permit calcs: X:\Public Health Programs\Air Quality\AQ Common\AQ Documents\u\us steel clairton\permits\operating permits\draft\clairton – tv-calcs – draft.xlsx], and reported actual VOC emissions are approximately 8 ton/yr. Without a primary VOC-laden air stream capable of being contained and collected, none of the identified control technologies can be used. As a result, there are no technically feasible add-on control options for further reducing VOC emissions from the by-products plant. A review of the RBLC (Process Code 81.190) and coke plant permits substantiates this conclusion; add-on controls have not been utilized to reduce VOC emissions from coke by-product recovery operations.

However, it is technically feasible to implement a LDAR program that covers the BPRP equipment.

Step 3 - Evaluate Control Options

The BPRP has a VOC PTE of 124 ton/yr. and reported actual (CY 2012) VOC emissions of 8.0 tons/yr., indicating that the existing gas blanketing system has an estimated VOC control efficiency of up to 94 percent. As the only technically feasible control option identified, ACHD evaluated whether the implementation of an LDAR program (in addition to the gas blanketing system) was economically feasible.

[95] Id.

[96] Leak Detection and Repair Compliance Assistance Guidance: A Best Practices Guide. (U.S. EPA) Available at http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf Accessed January 2015.

Using guidelines from Chapter 1 of the EPA Cost Manual, ACHD estimated that the incremental cost-effectiveness of the implementation of a LDAR program is $6,406 per ton of VOC removed - See Appendix A.

The analysis estimates the costs associated with initial set-up and implementation, including but not limited to identification and tagging of components, monitoring, and database development. It also estimates the annual costs, including but not limited to labor and insurance, are based on an interest rate of 7% and a program re-evaluation frequency of 10 years.

All costs, and nearly all calculated values used to determine costs, were determined using the methodology described in the "EPA Air Pollution Control Cost Manual, Sixth Edition" (document # EPA 452-02-001) and other technical resources available in the EPA Clean Air Technology Center.

The combined VOC control efficiency of the existing gas-blanketing system and a new LDAR program is 98 percent.

Step 4 – Select RACT

For the By-Products Recovery Plant, ACHD has determined that VOC RACT is:

- The continued use of a clean COG gas-blanketing system as required by Clairton's Title V permit.
- The implementation of a LDAR program consistent with the corresponding standards of 40 CFR Part 61, Subpart V, codified in 40 CFR 61.242-1 through 61.247.

I. RACT for VOC – Desulfurization Plant

Process/Unit description – Desulfurization Plant

Large quantities of COG are produced in the ovens during the coking process. The evolved COG exits the battery ovens through standpipes, is spray-cooled to precipitate tar and condense various vapors and routed to the collection main. The collected COG is routed to the By-Products Recovery Plant (BPRP), where a variety of valuable organic compounds are extracted, and then further processed by the Desulfurization Plant (DP) where hydrogen sulfide (H2S) and other sulfur compounds are removed. Sulfur dioxide (SO2) emissions are generated from the oxidation of H2S present in COG when it is combusted.

Desulfurization processes vary considerably from coke plant to coke plant. At Clairton, the DP primarily consists of two Claus Plants (one primary and one backup) and the Shell Claus Offgas Treatment (SCOT) Plant. The Claus Plant converts a large portion of the H2S and other sulfur compounds in the treated COG to elemental sulfur, which is sold. The treated COG exiting the Claus Plant is then routed to the SCOT Plant where it is processed and separated into three gas streams: a treated/low sulfur COG stream, a concentrated H2S stream, and an acid offgas stream. The H2S stream is returned/recycled to the Claus Plant for further sulfur removal and recovery. The acid offgas stream is incinerated by the SCOT Plant Incinerator.

The concentration of H2S in the COG exiting the DP is typically reduced to approximately 10 grains per 100 dry standard cubic feet (dscf) of COG, or approximately 0.045 percent sulfur.

Step 1 – Identify Control Options

According to information available in the aforementioned resources and Clairton's RACT submittal, VOC emissions from the DP could, in theory, be controlled with:

(a) Thermal Oxidization
(b) Carbon Adsorption
(c) Catalytic Oxidization
(d) Refrigerated Condensation
(e) Flaring
(f) Absorption (Scrubbing)

A concise description of each of these technologies is as follows:

(a) Thermal Oxidation

Thermal oxidizers are refractory lined enclosures with one or more burners in which the waste gas stream is routed through a high temperature combustion zone where it is heated and the combustible materials are burned. Thermal oxidizers typically operate at 1200 to 2100 degrees Fahrenheit with residence times typically ranging from 0.5 to 2 seconds. An efficient thermal oxidizer design must provide adequate residence time for complete combustion, sufficiently high temperatures for VOC destruction, and adequate velocities to ensure proper mixing without quenching combustion. The type of burners and their arrangement affect combustion rates and residence time; the more thorough the contact between the flame and VOC, the shorter the time required for complete combustion. Natural gas is required to ignite the flue gas mixtures and maintain combustion temperatures. Typically, a heat exchanger upstream of the oxidizer uses the heat content of the oxidizer flue gas to preheat the incoming VOC-laden stream to improve the efficiency

of the oxidizer. Thermal oxidizers can achieve a wide range of efficiencies, and usually achieve VOC vapor removal efficiencies in excess of 95 percent.[97]

Thermal Oxidation can be used over a fairly wide range of organic vapor concentrations. However, concentration of the organics in the waste gas must be substantially below the lower explosive limit of the compound being controlled. Accounting for economic factors, thermal oxidation performs best at inlet concentrations from approximately 1500 to 3000 ppmv, because the heat of combustion of the hydrocarbon gases is sufficient to sustain the requisite temperature. Otherwise, the emissions reductions benefit of the oxidizer is somewhat offset by the emissions created by the supplemental fuel required. While air stream pretreatment is generally not required, thermal oxidation is generally not recommended for controlling gas streams containing halogen (or sulfur) containing compounds, because of the resulting formation of corrosive gases (e.g. hydrogen chloride) and/or SO2.[98]

(b) Carbon Adsorption

Carbon adsorption is a process by which VOC is retained on a granular carbon surface (the adsorbent), which is highly porous and has a very large surface-to-volume ratio. Eventually, the adsorbent becomes saturated with the vapors and the system's efficiency drops. Regulatory considerations dictate that the adsorbent be regenerated or replaced soon after efficiency begins to decline. Compounds with high molecular weights greater than 50 and a boiling point greater than 50 degrees C are typically good candidates for adsorption. In regenerative systems, carbon adsorption systems operate in two phases: adsorption and desorption. Adsorption is rapid and removes most of the VOC in the stream. Desorption is the process by which the adsorbent is reactivated (typically with steam or hot air), and an absorbate (a solvent appropriate for the VOC) is used to collect the retained VOC. The absorbate is then recovered for reuse or disposal. VOC compounds that are difficult to desorb from the carbon media will significantly reduce VOC control-effectiveness. In non-regenerative systems, the adsorbent is simply removed and replaced with fresh or previously regenerated carbon. Removal efficiencies of 90 to 99 percent can be achieved using carbon adsorption.[99]

(c) Catalytic Oxidation

Catalytic oxidizers are similar to thermal oxidizers (the units are enclosed structures that use heat to oxidize the combustible materials). However, in a catalytic oxidizer, a catalyst is used to lower the operating temperature needed to oxidize the VOCs by lowering the activation energy for oxidation. When a preheated gas stream is passed through a catalytic oxidizer, the catalyst bed initiates and promotes the oxidation of the VOC without being permanently altered itself. Note that steps must be taken to ensure complete combustion. The types of catalysts used include platinum, platinum alloys, copper chromate, copper oxide, chromium, manganese, and nickel. These catalysts are deposited in thin layers on an inert substrate, usually a honeycomb shaped ceramic. VOC destruction efficiency is dependent upon a number of factors, including VOC composition and concentration, operating temperature, and the velocity of the gas passing through the bed. As the velocity increases, VOC destruction efficiency decreases. As temperature increases, VOC destruction efficiency increases. Catalytic oxidation is therefore most suited for air streams with low exhaust volumes, with little variation in the type and concentration of VOC, and where catalyst poisons or other fouling containments (e.g. silicone, sulfur, particulates etc.) are not present. Catalytic oxidation has been used effectively with very low VOC inlet loadings (around 1 ppmv). As with other types of incinerators, concentration of the

[97] Id.
[98] Id.
[99] Id.

organics in the waste gas must be substantially below the lower explosive limit of the compound being controlled. Catalytic oxidizers typically achieve greater than or equal to 98% VOC reduction.[100]

(d) Refrigerated Condensation

A refrigerated condenser is a control device that is used to cool an emission stream having organic vapors in it and to change the vapors to a liquid. The condensed organic vapors can be recovered, refined, and might be reused, preventing their release to the ambient air. A refrigerated condenser works best on emission streams containing high concentrations of VOC. A refrigerated condenser works best in situations where the air stream is saturated with the organic compound, the organic vapor containment system limits air flow, and the required air flow does not overload a refrigeration system with heat. The removal efficiency of a condenser is directly related to the lowest temperature that can be achieved in the condenser. Condensation is feasible for air streams with a high VOC concentration of few organic compounds. The greater the number of VOC components, the lower the temperature that must be maintained to achieve effective condensation. Removal efficiencies typically range from 50-98%.[101]

(e) Flaring

Flaring is an open-air combustion process typically applied when the heating value of the air stream cannot be recovered economically because of intermittent or uncertain flow, or when process upsets occur. In general, flare performance depends on a number of factors, including gas velocity, emission stream heating value, residence time in the combustion zone, waste gas/oxygen mixing, and flame temperature. If conditions in the flame zone are optimal, a non-assisted flare may achieve a VOC destruction efficiency of 98 percent or greater. It may be necessary to add supplementary fuel to the emission stream to achieve this destruction efficiency if the net heating value of the emission stream is less than 300 Btu/scf. For assisted flares such as steam-assisted or air-assisted units, combustion efficiencies may be lower.

Flares are typically unsuitable for the treatment of dilute gas streams because the costs of supplemental fuel needed to attain the minimum combustion temperature are prohibitive. Unlike afterburners, flares have no heat recovery capability that could produce credits for heat generated from combustion. Flares are also generally less effective than other devices in controlling organic vapors.[102]

(f) Absorption (Scrubbing)

Absorption (aka scrubbing) is a type of control technology that uses one or more methods to remove air pollutants, including diffusional impaction, reaction with a sorbent or reagent slurry, and/or absorption into a liquid solvent. It is widely used as a raw material and/or product recovery technique in the separation and purification of gaseous streams containing high concentrations of VOC, especially water-soluble compounds (e.g. methanol, ethanol, acetone and formaldehyde). Hydrophobic VOC can be absorbed using an amphiphilic block copolymer dissolved in water. However, as an emission control technique, it is much more commonly employed for controlling inorganic gases than for VOC. The suitability of gas absorption as a pollution control method is generally dependent on the following factors: 1) availability of suitable solvent; 2) required removal efficiency; 3) pollutant concentration in the inlet vapor; 4) capacity required for handling waste gas; and 5) recovery value of the pollutant(s) or the disposal cost of the unrecoverable solvent.

[100] Id.
[101] Id.
[102] Id.

Absorption for VOC emissions control is fundamentally limited by the temperature of the air stream and is therefore reserved for low temperature applications. High gas temperatures can lead to significant solvent or scrubbing liquid loss from evaporation. That loss translates to displaced VOC emissions and would inherently limit the VOC control-effectiveness. Absorbers typically achieve 70 to 99% VOC reduction.[103]

Step 2 – Eliminate Technically Infeasible Control Options

Each identified control option is technically feasible.

Step 3 - Evaluate Control Options

The uncontrolled VOC PTE of the DP is 398 ton/yr. [This is from the US Steel Clairton 2014 RACT submittal]. However, the existing DP/SCOT Plant incinerator has a VOC PTE of approximately 5.78 tons/yr[1]. (The existing DP/SCOT Plant incinerator is an example of thermal oxidation.)

The potential incremental VOC reduction (ton/yr.) of any of the technically feasible control options is therefore so low that none of those options are economically feasible. As a result, no additional analyses were completed.

Step 4 – Select RACT

ACHD has determined that VOC RACT for Desulfurization Plant (which includes the SCOT Plant) is the continued use of the SCOT Plant Incinerator. The incinerator will operate with a VOC limit of 1.32 lb/hr and 5.78 tons/yr. Operation of the incinerator shall be consistent with the other current requirements established for the unit in Clairton's Title V permit. In addition, the SCOT Plant Incinerator and the Desulfurization Plant shall be properly operated and maintained in accordance with good engineering and air pollution control practices.

[1]39 tpy based on X:\Public Health Programs\Air Quality\AQ Common\AQ Documents\u\us steel clairton\permits\operating permits\draft\clairton - tvcalcs – draft.xlsx

However, stack testing from November of 2015 shows highest test run of 1.32 lb/hr. 1.32 lb/hr * 8760 hrs/yr * ton/2000lbs = 5.78 tpy (stack testing report is "0052str2016-01-25scot")
Increase by 15% = (1.32 lbs/hr)*1.15 = 1.52 lbs/hr

[103] Air Pollution Control Technology Fact Sheet - Packed-Bed/Packed-Tower Wet Scrubber (EPA-452/F-03-018). Available at http://www.epa.gov/ttn/catc/dir1/fcataly.pdf. Accessed January, 2015.

United States Steel Corporation
Mon Valley Works
Clairton Plant
400 State Street, MS 71
Clairton, PA 15025

Coleen Davis
Senior Environmental Engineer

RECEIVED

APR 17 2014

ALLEGHENY COUNTY HEALTH DEPT.
AIR QUALITY PROGRAM

Via Hand Delivery

April 17, 2014

Ms. Sandra Etzel
Air Quality Program
Allegheny County Health Department
301 39th Street, Building #7
Pittsburgh, PA 15201

Dear Ms. Etzel,

Enclosed, please find the Reasonably Available Control Technology (RACT) Re-Evaluation for nitrogen oxides and volatile organic compounds for the United States Steel Corporation – Mon Valley Works – Clairton Plant. The RACT Re-Evaluation is being provided to the Allegheny County Health Department (ACHD) based on the letter concerning, "Reasonably Available Control Technology (RACT) Evaluation Request," dated December 6, 2013 from ACHD.

If you have any questions concerning the RACT Re-Evaluation, please contact me at (412) 233-1015 or CDavis@uss.com.

Sincerely,

Coleen Davis
Senior Environmental Engineer

RECEIVED

APR 1 7 2014

ALLEGHENY COUNTY HEALTH DEPT.
AIR QUALITY PROGRAM

amec

RE-EVALUATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY

Clairton Works

Clairton, Pennsylvania

Prepared for:

U.S. Steel Clairton Works
Clairton, Pennsylvania

Prepared by:

AMEC Environment & Infrastructure, Inc.
800 N. Bell Avenue, Suite 200
Pittsburgh, Pennsylvania 15106
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April 16, 2014

AMEC Project No. 3410140966

RE-EVALUATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY

Clairton Works

Clairton, Pennsylvania

April 16, 2014

AMEC Project No. 3410140966

This report was prepared by the staff of AMEC Environment & Infrastructure, Inc. under the supervision of whose signature(s) appear hereon.

Robert L. Romansik
Principal - Chemical

Christopher M. Dunay
Senior Associate Scientist

amec

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1.0 INTRODUCTION

U.S. Steel, Clairton Works, in Clairton Pennsylvania has developed a Reasonably Available Control Technology (RACT) analysis in accordance with the letter of request from the Allegheny County Health Department (ACHD) Air Pollution Control Division dated December 6, 2013. A RACT re-evaluation is required for incorporation into Allegheny County's portion of the PA State Implementation Plan (SIP) as part of the 8-hour ozone standard non-attainment designation for Allegheny County. On June 6, 2013, the US EPA proposed 2008 Ozone SIP requirements and is requiring the ACHD to re-evaluate NOx and/or VOC RACT, as codified in 40 CFR 51.

In 1993 USS performed a RACT analysis as part of the 1-hour ozone standard requirements. A second RACT analysis was conducted in 2006, as related to the 8-hour ozone re-designation. The RACT regulations and requirements were published in Article XXI, Section 2105.06 of the Allegheny Rules and Regulation for Air Pollution Control in November 1992. No additional sections or addendums have been written in Article XXI concerning RACT since the original RACT requirements in 1992 and therefore, the requirements in Section 2105.06, including the presumptive RACT requirements were applied in this RACT analysis. RACT applies to major sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOCs). U.S. Steel Clairton Works is a major source for both NOx and VOCs.

2.0 FACILITY SOURCES

The coke and coal chemicals production facilities at U. S. Steel Clairton Works (Clairton Works) are comprised of a complement of ten by-product coke batteries with an annual capacity of approximately 8.2 million tons of coal charged. The by-products plant at Clairton Works includes facilities for recovery of clean coke oven gas (COG), coal tar, light oil, anhydrous ammonia and elemental sulfur. Environmental facilities include a wastewater treatment plant and a Claus carbonate COG desulfurization unit. The plant produces a significant fraction of its electricity requirements and is self-sufficient in steam and cooling water.

Sources that are not regulated by another applicable technology or operational requirement in Section 2105 of Article XXI of the Allegheny County Air Pollution Control Regulations, or are not covered by presumptive a RACT requirement contained in Section 2105.06, are included in a case-by-case RACT analysis. U.S. Steel Clairton Works source categories that are included in the analysis, based on these criteria, consist of:

- Coke batteries #B, C, 1, 2, 3, 13, 14, 15, 19 and 20 underfire combustion stacks (NOx and VOCs)
- Coke battery emissions, including baghouse stack, traveling hot car, soaking, pushing and other unspecified fugitives (NOx and VOCs)
- Coke battery fugitives including charging door leaks, lid leaks, and offtake leaks (VOC only)
- Boilers #1, 2, R-1, R-2, T-1 and T-2 (NOx and VOCs)
- Desulfurization plant (NOx and VOCs)
- Flares (NOx and VOCs)
- Coke by-products recovery plant including tar decanters, surge tanks, powerhouse sumps, collector tanks, cooler sumps, equipment leaks, BP pitch traps and TDS boxes (VOCs only)
- Wastewater treatment units and aeration basins (VOCs only)
- Miscellaneous methanol usage for lid slurry, tanks and airlines (VOCs only)
- LO collecting tanks, LO barge loading, and LO decanting (VOC only)
- Quench Towers (VOC and NOx)

Sources that are excluded from further RACT analysis, based on presumptive RACT or other applicable RACT control requirements that are already in-place, consist of the following source categories:

- Light oil transfer facility (VOCs controlled by gas blanketing in the by-products plant) – See discussion of by-products in Section 4.4
- Boilers and space heaters with a heat input value less than 50 MMBTU/hr each (presumptive RACT, Section 2105.06.d, for NOx)

- Storage tanks greater than 2,000 gallons (Section 2105.12 requirement for VOC control)
- Parts Washer (Section 2105.15 requirement for VOC Degreasers)
- Paints and Thinners (Section 2105.10 for Surface Coating)
- Heavy duty motor vehicle and tug boat exhausts (mobile sources)

Provided in **Table 2.1 and 2.2** are source-by-source listings of NOx and VOC emission sources at Clairton Works, respectively. Where a source has an existing presumptive RACT requirement or VOC control requirement, or intends to be covered by a presumptive RACT requirement (if not pre-existing), it is identified in the table.

2.1 FACILITY CHANGES SINCE 1993 AND 2006 RACT ANALYSIS

Over the past 15 years, U.S. Steel undertook and continues to implement a COG consumption optimization project. The result of this project provides U.S. Steel with the capability to consume COG produced by the Clairton plant that would otherwise be flared. As a result, it has greatly reduced the amount of natural gas consumed by facility combustion units (as COG replaced a large majority of the natural gas consumed by these units). The result has been the reduction of actual NOx emissions, as well as fossil fuel usage for the combination of U.S. Steel facilities (Clairton, Edgar Thomson and Irvin). It is now a standard practice to operate with the intent to consume all COG, where feasible.

Since the 2006 RACT Analysis, the following changes have taken place at Clairton Works:

1. 2008 - Installation of new Battery C, which replaced existing Batteries 7, 8 and 9. The new battery contains the latest emission control technology and emits less air pollution per ton of coke produced than the old batteries. Battery C has 84 ovens which have a design production rate of 36.8 tons of coal charged per oven for a design coking time of 18 hours to produce 24.7 tons of blast furnace coke per oven. The new Battery has a PROven® (Pressure Regulated Oven) system, developed by Uhde Corporation with staged air combustion. Coke produced from Battery C is sent to a new coke screening station for rail car loading and offsite transport.

2. 2008 – Installation of new Battery C Quench Tower. This tower and new settling basin are designed with a state-of-the-art Kiro-Nathaus baffle system to control particulate emissions which are the first of its kind to be installed in the United States.

3. 2013 – Installation and start up of 5A and 7A Quench Towers. This tower and new settling basin are designed with a state-of-the-art Kiro-Nathaus baffle system to control particulate emissions.

2.2 EMISSION ESTIMATES

Potential and actual emissions for sources included in the case-by-case RACT analysis are also provided in **Tables 2.1 and 2.2**. If a source has an existing emission limit, the limit is listed in the potential emission column, and denoted as such. Actual emissions were based on the 2012 reporting year; emissions were obtained from Clairton Works' 2012 emissions spreadsheet summary and the 2012 Emissions Inventory Production Report, generated through PADEP's AES*Online. Note: all RACT analysis was performed using the potential to emit, unless otherwise noted, for cost effectiveness analysis purposes.

3.0 CONTROL TECHNOLOGIES OVERVIEW

3.1 NOX CONTROL TECHNOLOGY REVIEW (PRE AND POST-COMBUSTION TECHNOLOGIES)

A study performed for The Lake Michigan Air Directors Consortium titled "Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis," was published on March 30, 2005 The analysis identified potentially feasible NOx and VOC, amongst other pollutants, control technologies for iron and steel facilities in the Midwest region. One of the facilities in the study was an integrated iron and steel plant with a recovery process, the same basic type of operation as the U.S. Steel Clairton facility. The study utilized the 1994 "Alternative Control Techniques Document- NOx Emissions From Iron and Steel Mills" document, supporting documents to the coke battery NESHAPs regulation, as well as other publications and resources In addition to this study, in December 2004 an "Assessment of Control Technology Options for BART-Eligible Sources" was prepared for the Northeast States for Coordinated Air Use Management. This study evaluated potential NOx and VOC controls for Industrial Boilers. Both of these studies were supported by vendor supplied literature as well. From these documents, various technical information was relied upon in consideration of the U.S. Steel RACT analysis. A recent review of literature concerning steel mills, as well as steel mill sources did not locate any additional studies which would supplement or update the referenced documents, including those by EPA, NEUSCM, regional planning organizations. Information concerning the potential emissions reductions that could be achieved by specific controls was stated as follows:

General NOx Control Technology Type(s)	Potential Control Efficiency (%)[1]	Technical Concerning Technology Effectiveness
Low NOx Burners (LNB)	25-40	• Minimum temperature requirements • Minimum oxygen levels • Flame length
Flue Gas Recirculation (FGR) or Overfire Air (OFA)	30-50	• Minimum temperature requirements • Minimum oxygen levels • Fan capacity • Furnace pressure • Burner pressure drop • Turndown stability
LNB + FGR or OFA	50-72	See LNB and FGR above

General NOx Control Technology Type(s)	Potential Control Efficiency (%)[1]	Technical Concerning Technology Effectiveness
LNB + Selective Non-Catalytic Reduction (SNCR)	50-89	• High temperature requirements • Ammonium sulfate formation • Ammonium water and wastes • Ammonia slip
Selective Non-Catalytic Reduction (SNCR)	20-45	See SNCR above
Ultra Low NOx Burners (ULNB)	75-85	See LNB above
Regenerative Selective Catalytic Reduction (RSCR)	50-70	• Only applied on large boilers at biomass plants • Requires extensive new ductwork, heat exchangers and rerouting of gas • Significant pressure drop increase
Selective Catalytic Reduction (SCR)	70-90	• Limited temperature range • Ammonium sulfate formation/fouling • Ammonia slip

1 The potential control efficiency is based upon a percentage decrease from a baseline emission estimate. The baseline emission estimate is for indirect fired combustion units firing natural gas with standard burners that typically operate on high volumes of excess air and no flue gas recirculation or staged air.

From the above table the hierarchy of potential control efficiencies for each type of general control technology can be identified, indicating that application of ULNB with SCR is the best

Although RSCR is not included in these literature reviews, it was added for completeness 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 Therefore, it was not considered further as a technically feasible option at this time.

Consideration of the specific unit design, operation and intent must be taken into account when determining if an option is technically feasible for that specific application. As an example, there

may be replacement burners available for a boiler that could potentially result in a lower NOx emission rate. However, the low NOx burner application may only result in reduced emissions while the boiler is operated at or near full load and may not result in reductions if the boiler is operated at various loads, swing loads or substantially low loads. In a case where the boiler being reviewed does operate on varying loads or swing loads and continuous emission reduction guarantees cannot be obtained, the technology would be considered technically infeasible. Based on review of the referenced documents, literature available from vendors, engineering judgement and experience, the following NOx control options were identified as potentially technically feasible for the various source categories at U.S. Steel Clairton Works:

1) Coke battery underfire combustion stacks

- LNB / ULNB – No, these are direct fired heatings systems.
- FGR – No, 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.
- RSCR – No, not proven on coke batteries and rerouting would be too extensive.
- SNCR – Yes, with preheating of the exhaust gas.
- SCR – No, due to large potential outlet temperature and volumetric flowrate changes.

2) Coke battery fugitives – None. There are no combustion devices associated with these units, so pre-controls are not an option. Due to the fact that the volume of air that would have to be collected to capture the fugitive emissions would result in a high dilution of the concentration of NOx and VOCs, to the point that concentrations would be below the range of control technology capabilities (i.e., less than the minimum inlet concentration requirements) or the additional heat input required to heat the exhaust stream to a temperature that could be controlled by an add-on technology (i.e., minimum 650°F for SCR and 1,600°F for SNCR) coupled with the large size of the control equipment that would necessary to treat the exhaust (due to the volumetric flow rates) the capital and operating costs would not be feasible. Where fugitives are already partially or fully captured and ultimately directed to a vent or stack (i.e., fugitives captured by the coke side shed or moveable hood pushing emission control and directed to a baghouse), the exhaust of the vent or stack was included in this study.

3) Boilers

- LNB / ULNB – Yes
- FGR – Yes
- OFA – Yes
- RSCR – No, boilers are of sufficient size but not demonstrated while firing alternative fuels such as COG. No vendor guarantees would be provided without extensive testing on alternative fuels.

- SNCR – Yes
- SCR – Yes

4) Desulfurization plant (incinerator)

- LNB / ULNB - No, the incinerator burner nozzles, oxygen and fuel feed, and combustion chambers are already inherently designed for NOx control; no changes to these units are available without impact on emission reduction performance of other pollutants (which could cause a violation of the performance requirements).

- FGR – No, the incinerator is a regenerative type unit. As such, it already employs flue gas recirculation as part of the system design. The incinerator is not designed to handle any additional volumetric flow.

- RSCR – No, RSCR has not been proven on incineration units. No vendor guarantees would be provided.

- SNCR – Yes, with preheating of the incinerator exhaust gas.

- SCR – Yes, with supplemental heat reduction of the incinerator exhaust gas.

5) Flares – None; the flares at Clairton Works operate on an emergency basis only and burner packages and FGR that limit NOx are not amenable to such flares; add-on controls cannot be used on flares (see Operational Changes section for more information on changes to the method of operation).

3.2 OPERATIONAL CHANGES

3.2.1 Fuel Switching

A previous operational change that reduced NOx emissions was due to the switching of fuels. Prior to the RACT analyses in 1993 and 2006 U.S. Steel had the ability to utilize (combust) coal and fuel oils in certain units. These solid and liquid fuels can produce higher levels of NOx and VOC emissions than gaseous fuels, dependent on the type, design and operation of a boiler. However, as previously referenced, U.S. Steel has implemented a fuel optimization program over the last 15 years. As a result, U.S. Steel has restricted the usage of solid and liquid fuels such that only coke oven gas (COG) which is a by-product of the coking process and natural gas can be burned in onsite combustion units. These gas streams are considered to inherently be amongst (if not) the cleanest burning fuels for the combustion units at Clairton, thereby, in themselves producing low emission rates. It is used as a primary plant fuel gas and is supplemented with natural gas where needed. If clean COG is not consumed at the Clairton Works, it is sent downstream to the U.S. Steel Mon Valley operations as a fuel gas. Where excess COG is produced, it is combusted in the COG flares at Irvin. Generally, it has been

found that NOx and VOC emissions produced from combustion of COG are equal to or less than emissions produced while firing natural gas. Coupled with the reduction in COG flaring, the practice of burning COG as the primary or base-load fuel wherever possible produces the lowest emissions of NOx and VOCs (plant-wide) than any other fuel burning scenario. Due to this, fuel switching is not considered an option for RACT purposes.

3.2.2 Modification To Excess Oxygen in the Combustion Process

To a certain extent, the higher the excess air used for fuel combustion, the higher the potential NOx generation. Above a certain mixture ratio of air to fuel, no additional NOx is formed. Control of excess air used in the combustion process can typically only be performed in equipment designed for contained combustion, such as indirect fired equipment with chambers or windboxes. With the exception of certain types of boilers, coke making equipment (i.e., coke batteries, desulfurization units, flares) are not amenable to substantive excess oxygen control. These operations rely on certain flame temperatures and flame lengths to adequately process coke products. The excess oxygen content is already tempered to ensure adequate heat distribution and elimination/minimization of opacity (smoke). Operation of these processes at levels below certain air/fuel ratios will result in incomplete combustion, causing visible opacity and permit deviations. For these operations potential reduction of excess air is not considered an option that would produce any reasonable or consistent reduction in NOx emissions. Reduction in excess air is naturally associated with a pre-combustion technique, like the use of Low NOx Burners (LNBs). Additionally, reduction in excess air can lead to an increase in VOC emission production in certain processes. Flares are also direct fired sources that are used to either combust COG (battery system) or ammonia (by-products recovery plant). Flare devices are also not equipped with air-to-fuel mixture controls. With the exception of some smaller ground level flares that are originally designed for continuous load, NOx and VOC emissions cannot be controlled. U.S. Steel does not employ these types of flares at Clairton. Due to these issues, the control or potential reduction in excess air (with the exception of boilers) in-itself was not considered to be an option for control of NOx in this RACT analysis.

3.3 VOC CONTROL TECHNOLOGY OVERVIEW FOR CLAIRTON WORKS

Coke facility VOC emissions are not typically controlled by add-on technology (with the exception of desulfurization plant emissions) due to the large volume of gas and low VOC concentrations associated with the operations. 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.

As indicated in the NESHAPs regulations for Coke Oven Batteries (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 RACT Order #234. Therefore, no additional potential controls of VOC from Coke Oven Batteries were addressed in this RACT analysis.

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.

VOC emission sources that are not discussed in the technical issues section above, or are not covered by an applicable requirement in Section 2105 consist of the wastewater treatment (WWT) basins, and the methanol use processes. Emissions from the WWT basins are due to evaporation and aeration of the basins. These are large open-air basins, spanning over 41,000 square feet in surface area. Capture of the emissions from the basins alone would require the enclosure of the basins. This is not considered a technically feasible option due to the extensive size that would be required of the enclosures. In such an enclosure, due to the surface area and depth, the volumetric flowrate that would be needed to evacuate emissions would be extremely large (to overcome the pressure differential losses across the basin). Therefore, VOC concentrations in the exhaust gas would be low, and any add-on VOC control device would be very large as well. Additionally, extensive structural analysis would be required to design the enclosures. Based on these facts the capture and control of VOC from the basins was not considered. The potential control of VOC in-situ was also reviewed. U.S. Steel, in conjunction with the USEPA, undertook a project in the past to attempt to reduce VOC concentrations in the wastewaters. The project consisted of loading the basins with aqua-phase powdered activated carbon (PAC). The PAC absorbs the VOCs, then can be filtered from the basins and sent offsite for regeneration. The study was performed under the review of EPA. It was identified that PAC could not be used because its use resulted in the toxic desorption of certain volatiles; as certain volatiles were adsorbed other were displaced from the carbon. This effect caused short burst toxic loadings which highly degraded the biological activity in the basins. It was concluded that PAC could not be used. No other technology for VOC reduction was considered to be feasible. Based on this study and the issues surrounding capture of emissions from the basins, potential reduction of VOC from the WWT basins was not considered further in this analysis.

Methanol is used in three places at Clairton Works. First, it is injected into compressed air lines in winter months to prevent condensate from freezing. Second, it is added to battery sealing material during winter months to prevent freezing. Finally, it is also used to wash the cryogenic process vessel packing (i.e. quartzite stones) in preparation for maintenance or turnaround activities.

The use of methanol as airline antifreeze results in its release as vapor along with the air at the location of numerous compressed air consumers. Based on this widely disperse release

mechanism, there would be no practical way to capture or control the release. Discussion with vendors and other steel industry operators indicates that there have been no material substitutes identified for these purposes either.

When used as an antifreeze additive to battery sealing materials, methanol is added in small quantities at a multitude of locations. Release would occur as vapor at the point of use. That is, as the sealing material is applied at each lid, the methanol would be released as a vapor. Proper use of the sealing material prevents releases from the oven lids and off takes, and is an integral compliance mechanism for the NESHAP. Methanol has proven to be the best material for this application. Based on this release mechanism, there would be no practical way to capture or control the release.

The methanol used for washing the regenerators in the cryogenic process in anticipation of maintenance activities is stored in tanks that are controlled by the byproduct plant gas blanketing system. Therefore, any release of methanol vapors from these tanks are captured and processed through the gas handling system. Based on the present control mechanism, no additional controls are necessary.

For other sources of potential VOC emissions, technologies such as thermal oxidation, carbon adsorption, and condensations were reviewed, where applicable.

3.4 RBLC DATA BASE REVIEW FOR IRON AND STEEL FACILITIES

In addition to the documents referenced above in Section 3.1, USS Clairton also researched USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database for application of NOx and/or VOC control technology for iron and steel facilities and specific applicability to US Steel Clairton Works. Appendix A shows a summary of RBLC database findings relative to source types of interest. The determinations presented in Appendix A do not indicate any application of controls or emission limits for NOx or VOCs which are more stringent than current emission rates at USS Clairton Works for the source types under review.

4.0 SOURCE BY SOURCE EMISSION CONTROL REVIEW

4.1 COKE OVEN BATTERIES

4.1.1 Battery Design Configurations at Clairton Works

Battery C

The most significant change since the 2006 RACT analysis was the installation of new battery C. Battery C replaced existing Batteries 7, 8 and 9. The new battery contains the latest emission control technology and will emit less air pollution per ton of coke produced than the old batteries. Battery C has 84 ovens which have a design production rate of 36.8 tons of coal charged per oven for a design coking time of 18 hours to produce 24.7 tons of blast furnace coke per oven. The new Battery has a PROven® (Pressure Regulated Oven) system, developed by Uhde Corporation with staged air combustion. This system regulates pressure within each oven chamber where the collector main operates under a negative pressure during coking in order to significantly reduce fugitive emissions from the ovens during charging and coking. NO_X emissions will be minimized through the employment of a staged combustion system. Coke produced from Battery C is sent to a new coke screening station for rail car loading and offsite transport. In addition to Battery C, a new quenching tower was installed. This tower and new settling basin are designed with a state-of-the-art Kiro-Nathaus baffle system which are the first of its kind to be installed in the United States. Its main purpose was to control particulate emissions. This battery was permitted as an ACHD BACT source in the permitting process. There have been no significant changes to the new battery. Therefore, RACT for this new Battery is considered to be the setup, operation and control of emissions in accordance with good engineering practices and the terms and conditions of the Minor Source Installation Permit #0052-I011. With respect to existing Batteries, no additional changes are technically feasible.

Batteries B, 1, 2, 3, 13, 14, 15, 19 and 20

With the exception of the new Battery C design, there are numerous other heating (underfiring) design configurations for by-products coke batteries that have been and are being used worldwide. The underfiring systems at Clairton Works' batteries can be divided into three broad categories: gun-flue, with one combustion air port per burner (Wilputte batteries 1, 2 and 3); gun-flue, with multiple combustion air ports per burner (Carl Still batteries 13, 14, 15 and B); and underjet (Koppers-Becker batteries 19 and 20). All of the batteries are equipped with regenerators (also called recuperators in some applications) that are massive structures made

of refractory brick and located beneath the ovens and heating flues. The regenerators are divided into two groups which alternate between first being heated by the products of combustion leaving the heating flues and then preheating the incoming combustion air.

In gun-flue batteries, fuel gas enters the battery from the gas distribution piping into a horizontal gas duct (gas-gun) constructed of refractory brick extending the length of each wall below the oven floor elevation. Short vertical flues (risers) branch vertically off the gas-gun and lead to a replaceable refractory nozzle brick containing a sized, calibrated opening which regulates the gas flow to each of the vertical flues. At the batteries with one combustion air port per burner, preheated combustion air mixes with the fuel gas at the bottom of the heating flue; at the batteries with multiple combustion air ports per burner a portion of the preheated combustion air mixes with the fuel gas at the bottom of the heating flue, and the remaining combustion air is "staged" (i.e., it is introduced into the flue and mixed with the partially consumed fuel at refractory ports spaced along the height of the flue). The primary reason for staging the introduction of combustion air is to maintain an even vertical temperature over the height of the flue.

Underjet batteries are built with a "basement" beneath the regenerators. Fuel gas is distributed to the individual heating flues through a system of piping in the battery basement. The fuel gas passes vertically through burner piping equipped with an orifice or metering pin to regulate the gas flow to each flue. After flowing through the metering device, the fuel gas ascends through a vertical gas duct (riser) built integrally into the regenerator and flue support walls to the base of the heating flue. The Clairton Works underjet batteries include a feature whereby the fuel gas entering the risers passes through a venturi nozzle designed to extract a certain quantity of flue gas (products of combustion) from the regenerator and mix it with the fuel gas as it travels to the burner. This dilution of the fuel/air mixture increases the length of the flame and, like the staged air design described above, flue gas recirculation in the underjet batteries is intended to maintain an even temperature over the height of the flue.

4.1.2 Battery Underfiring Fuels

The primary fuel for the Clairton Works batteries is coke oven gas (COG). The relevant characteristics of COG are discussed below. However, under rare circumstances, stabilized natural gas may be used as underfiring fuel. For example, if several of the batteries were in "idle hot" condition because of market demand or other circumstances, the production of COG might

be less than required for both the operating and idle batteries, stabilized natural gas would be used to supply the deficit. Natural gas is "stabilized" to match the characteristics of COG by adding air to the natural gas thus maintaining the same wobbe index (Heating Value ÷ Square root of specific gravity). Under similar combustion conditions for the batteries, natural gas is expected to produce more NOx, as compared to firing COG. Therefore, using natural gas as the primary fuel for underfiring would be detrimental to NOx reduction. However, natural gas must be included as an alternative fuel for the Clairton batteries in case of the temporary loss of adequate volumes of COG and as a normal supplement to COG.

4.1.3 Factors Affecting NOx Formation at Clairton Batteries

Many factors affect the production of NOx in coke batteries; some increase and some decrease NOx. Although many factors are unknown, this discussion of NOx production at Clairton Works' batteries will first address overall known factors and then the peculiarities of each of the three underfiring systems in regard to NOx formation.

Plant-wide factors favoring NOx formation:

- Coke oven gas, the primary fuel, contains significant concentrations of hydrogen and carbon monoxide content (approximately 50% and 5% respectively) that tend to make flame temperature higher, favoring NOx formation.

- Coke oven gas contains N2, a portion of which results from air infiltration during oven charging and at the base of the doors, into the coke ovens near the end of the coking cycle. In both charging and door infiltration, a portion of the O2 from the air is consumed in combustion within the process. This results in a N2/O2 ratio somewhat higher than the ratio in air; therefore more N2 is available for NOx formation.

- Batteries are typically operated with relatively high excess combustion air with flue gas O2 range of approximately 8% to 12%.

- Combustion air is preheated in each battery's regenerators resulting in higher flame temperatures and favoring NOx formation.

Plant-wide factors suppressing NOx formation:

- Clairton Works' by-products plant includes a unique cryogenic process for cleaning COG. This process is extremely efficient in removing nitrogen-bearing organic compounds, e.g. pyridine, from the cleaned COG.

- Two primary sources of variability in COG quality are battery operations and by-products plant operations. With ten batteries, any operating anomaly at any one battery is dampened by the number of other batteries in operation. The cryogenic COG cleaning

system, unlike other by-products processes, is unaffected by factors such as weather and therefore minimizes the variability in COG composition.

Carl Still batteries, factors favoring NOx formation:

- In this gun-flue design, fuel enters the burners after passing through the flue which runs through the very hot section of the battery brickwork beneath the oven floor elevation and the top of the battery regenerators. The combination of contained hydrocarbons, N2 and high temperature possibly favors formation of cyanide compounds that are precursors to NOx formation in the combustion zone.

Carl Still batteries, factors suppressing NOx formation:

- Aside from Battery C, the staged air design of the Carl Still batteries is probably the most effective NOx suppression factor in battery design.

Koppers & Wilputte batteries, factors favoring NOx formation:

- In this gun-flue design, fuel enters the burners after passing through the flue which runs through the very hot section of the battery brickwork beneath the oven floor elevation and the top of the battery regenerators. The combination of contained hydrocarbons, N2 and high temperature possibly favors formation of cyanide compounds that are precursors to NOx formation in the combustion zone.

Koppers & Wilputte batteries, factors suppressing NOx formation:

- These batteries have no battery-specific design features that suppress NOx formation.

Koppers-Becker batteries, factors favoring NOx formation:

- The flue gas recirculation design of involves mixing flue gas and fuel gas and then delivering the mixture to the burner via the riser that passes through the hot regenerator section of the battery. The combination of contained hydrocarbons, N2 and high temperature possibly favors formation of cyanide compounds that are precursors to NOx formation in the combustion zone.

Koppers-Becker batteries, factors suppressing NOx formation:

- Flue gas recirculation tends to inhibit NOx formation in the Koppers-Becker batteries; however as discussed above, the path of the mixed flue gas and fuel gas through the regenerators is an offsetting factor.

4.1.4 General Retrofit Capability of NOx Reduction Technology Options

The discussion above suggests potential NOx reduction from retrofit technology or changes in operating practices. However, there is no feasible retrofit or operating practice change applicable to Clairton Works' existing batteries.

- Reduce hydrogen content of COG (lower flame temperature): Hydrogen is one of the natural components of coal and H2 is one of the normal products of the destructive distillation (coking) of coal. The H2 content of COG is not materially affected by operating practices or coal properties.

- Reduce N2 and/or CO content of COG: In addition to naturally occurring N and O in the molecular structure of coal, the principal sources of N2 and CO in COG are associated with environmental performance. Air is introduced during oven charging as a result of the strong aspiration (vacuum) required during charging to minimize charging emissions and meet emission standards. During charging, some air is drawn into the oven being charged, and some coal and gasses are burned in the O2-deficient atmosphere producing CO. The N2 content of the air remains in the COG. Reducing aspiration during charging would be counterproductive because it would result in increased emissions of particulate matter, and organic compounds including VOC.

- Also, some air is drawn into the bottom of the ovens near the end of the coking cycle. Some coke and gasses are burned in the O2-deficient atmosphere producing CO. The N2 content of the air remains in the COG. Increasing pressure in the collector main to avoid the slight negative pressure in ovens nearing the end of the coking cycle would lead to increased door leaks including emissions of VOC. Therefore, increasing oven pressure is both impractical and counterproductive as a means of reducing NOx emissions from battery combustion stacks.

- Coke batteries are operated at a relatively high excess air level compared to some other combustion processes. Excess air in coke ovens is needed to maintain compliance with other battery stack emissions regulations, namely the Article XXI and NESHAPs requirements. A source of emissions from battery stacks is coke oven gas leakage from the oven chambers into the combustion flues. This leakage typically occurs at local sites where imperfection in the oven walls exist allowing some leakage. Excess air allows the leaking gas to be efficiently burned instead of being emitted from the stack as particulate matter or VOC. Clairton Works' procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. In this balance, minimizing excess air is important as a fuel conservation method. Also, 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. Additionally, operation with sufficient excess air is needed to assure complete combustion of the COG that can be subject to heating value variability.

- It is not feasible to reduce the temperature of preheated combustion air. All of the batteries are constructed of refractory brick; the regenerators are beneath the ovens and heating flues and are an integral part of the structure. Revising the regenerators would literally require dismantling the battery.

- Reduce or eliminate preheating of the fuel gas upstream of the burners: It is not feasible to reduce the temperature of fuel entering the burners. As described above, fuel passing through the gun-flues in Batteries 1-3, 13-15 and B or the risers in Batteries 19 and 20 is subjected to heating from the surrounding ovens, heating flues and regenerators.

Revising the path of the fuel gas to the burners would literally require dismantling the battery.

- Replacing burners with low-NOx burners: The number of burners per battery at Clairton Works ranges from 1,736 burners in Batteries 13, 14 and 15 to 2,508 burners in Battery B; the ten current Clairton Works batteries have a total of 20,104 burners. The burners are located deep within the refractory structure of the battery.

4.1.5 Design Considerations and Limitations for Post-Combustion NOx Control

The regenerators in coke batteries significantly increase their fuel consumption efficiency; for COG-fired batteries the increased efficiency is at least 35% (Coke Battery Heating, Theory and Practice, USS Research Laboratory, 1982). However, in doing so, they present design obstacles to post combustion NOx control. Air flow reversals occur every twenty to thirty minutes in typical batteries; Clairton Works' batteries are operated at these industry-norm reversing cycles. The reversals result in step changes in temperature and flow to the battery combustion stack. In fact flow is essentially stopped for the short period of time when the reverse actually occurs. "Waste heat," or stack temperature, changes as the regenerator heating the incoming combustion air proceeds through the process; then when a reverse occurs, waste heat temperature increases step-wise then decreases until the next reverse occurs.

- SNCR: SNCR is impractical because of the low waste heat temperature downstream of the regenerators. A screening calculation based on EPA's Control Cost Manual, 6th Edition shows that the cost of natural gas required to raise the temperature of the flue gas, even under the most favorable conditions is in excess of $37,000 per net ton of NOx removed at the USS MVW natural gas price of $9.41/MMBtu (See Section 5 for more cost analysis detail).

- SCR: The cost of applying SCR to coke batteries is adversely affected by some unique characteristics of the flue gas stream. First, as discussed above the NOx concentration undergoes significant step changes as firing changes from coke side to pusher side, second, there are significant short-term trends in NOx concentrations, and third, there is a nearly instantaneous change in flow from the normal firing rate to virtually zero and back to "normal." These factors are a naturally-occurring result of battery reverses and oven taper. Heating reverses and oven taper are essential characteristics of by-product coke batteries that are literally impossible to change. SCRs operate within a narrow window of temperature, flow and NOx emission rates. The catalyst activation energy and ammonia feed-forward system are not capable of handling significant or immediate swings in these parameters. Operation outside of those parameters will result in significant ammonia slip, where the ammonia will not react. Vendors will not guarantee any efficiency or ammonia slip for operations outside the narrow parameters. Due to these facts SCR is not considered technically feasible. No battery is known to have utilized this technology.

4.2 BOILERS

4.2.1 Description and Operation

The six facility boilers were reviewed for potential control of NOx emissions, in accordance with the applicable control technologies or methods identified in Section 3.1. Potential control methods for VOC emissions are described in this Section. Boiler 1 is a cyclone type rated at 760 MMBTU/hr heat input, boiler 2 is four-wall-fired rated at 480 MMBTU/hr, and R1, R2, T1 and T2 are packaged wall-fired units (R1 and R2 are each rated at 229 MMBTU/hr, and T1 and T2 are each rated at 156 MMBTU/hr). Boilers number R1 and R2, and T1 and T2 are identical units by design and size, therefore only one boiler of each set was reviewed (since the results for the identical boiler would be the same). The operational difference amongst the boilers is potential variation in steam output that is required on a yearly basis. Boilers #1 and 2 operate continuously throughout the year to provide the primary steam demands; they are typically only shutdown for annual outages (maintenance). Based on normal operations steam demands, on a yearly average basis Boilers 1 and 2, is between approximately 50-75% of rated load. Boiler 1 is normally operated at a base-load (consistent supply rate) with Boiler 2 operating in the swing-load mode (remainder of the load requirements at any given time). When either Boiler 1 or 2 are down, the four remaining boilers (R1, R2, T1 and T2) are operated to provide the required steam demands. The steam production capability for combination of the four boilers (R1, R2, T1 and T2) is approximately equivalent to the steam capability of Boiler #1. Annual outages are planned during periods of lower steam demand (e.g. summer) so that during annual outages less steam is required throughout the plant; typically boilers R1, R2 and T1 operate near rated load and T2 is operated as a swing load. Annual outages occur for a duration of approximately 14 to 30 days per year. However, if an unexpected outage of either Boiler #1 or 2 occurs, the remaining four boilers will be operated to supplement the steam demand. In light of this, actual annual emissions from the four boilers are significantly lower than their potential annual emissions (See Table 2); there are no annual operating restrictions on any of the boilers. This flexibility, to operate any of boilers R1, R2, T1 and T2 on an unlimited basis at any given time, is necessary to assure that sufficient steam supply will always be available (in case of an unexpected extensive or permanent shutdown of Boilers #1 or 2).

4.2.2 Factors Affecting NOx Formation

As indicated in Section 3.1, all identified potential NOx reduction techniques are technically available for use in each of the boilers. These technologies were reviewed for the same boilers

as part of the previous RACT study; however, their technical and economic feasibility analyses were based on firing different fuels than those which are used now. In the previous studies, coal and fuel oil were capable of being fired in the boilers. As previously indicated, the boilers are now only permitted to fire COG or natural gas.

Additionally, boiler operation automation has been significantly upgraded, providing a greater capability to run the boilers more efficiently (resulting in less NOx formation and VOC emissions). More specifically, Boiler 1 operates the bottom burners as fuel rich and the top burners as fuel lean, thereby simulating staged air combustion. The other boilers contain oxygen sensors that allow for better control of air-to-fuel ratios. Stack tests have been performed on all the boilers since the previous RACT analysis. Test results show lower oxygen rates at the flue gas outlet. This implies that the boilers are generally operating at a low excess air rate, which results in lower formation of NOx. Low excess air is one of the same general concepts that are achieved by low NOx burners, and can be an effective NOx reduction technique in-itself.

Each of the six boilers is limited to a NOx short term emission rate of 0.54 lbs/MMBTU, based on the previous RACT Order. Continuous Emission Monitors (CEMS) have been installed on Boilers 1 and 2 for NOx and O_2 monitoring. A review of 2013 CEMS data for Boilers 1 and 2 indicates that the boilers annual average NOx emission rates are typically half or less of the permitted limits, indicating that the boilers are being operated effectively for the age, types and size of these boilers. The most recent stack test for boilers R1, R2, T1 and T2 indicate that the NOx emission rates ranges from 0.132 to 0.2 lbs/MMBTU. All test results are based on firing COG, the primary fuel. It is assumed that emission rates would be approximately equivalent while firing natural gas. These NOx emission rates for boilers R1, R2, T1 and T2 are generally lower than emission rates commonly associated with packaged natural gas fired boilers that employ low NOx burners. Burner manufactures have indicated (quoted) that replacement burners would not achieve a reduction in NOx, based upon the actual emission rates that are currently being achieved, for Boiler #2, R1, R2, T1 and T2. Boiler 1 is currently operating at or below burner manufacturer's indicated rates during ozone season. Additionally, due to the low excess air already being achieved, FGR or additional OFA will not be feasible; further suppression of excess air by these means would likely terminate the flame or pilot (which has been seen in cases like this before). Greater reduction in excess air would also lead to incomplete combustion, resulting in an increase in VOC and opacity emissions. In a retrofit

situation the boiler design (i.e., windbox, FD/ID fans, damper positions, burner locations, etc.) would have to be modeled by computer simulation to identify the NOx emission rates that can be achieved through retrofitting, and whether it could actually produce lower emission rates. Boiler/burner vendors would not quote potential emission reduction for such changes due to these issues. Therefore, pre-combustion controls were not reviewed further for Boilers #2, R1, R2, T1 and T2.

Post combustion controls were reviewed for all six boilers.

4.2.3 VOC Emissions Reduction

The previous RACT analysis reviewed the potential application of a regenerative thermal oxidizer on the exhaust stack of the boilers. The lowest cost effectiveness was calculated to be $185,000 per ton of VOC controlled. The VOC emission rate for each boiler has not changed in any significant manner, and the technology to control VOCs has not changed in any significant manner as well. Therefore, due to the high cost effectiveness, thermal oxidation was not further reviewed. Other VOC reduction technologies, such as carbon adsorption or condensation were not reviewed due to the low concentration of VOCs in the exhaust gas along with a requirement to add chillers before these control devices to reduce the temperature to within the control device range. These technologies were considered as technically infeasible.

4.3 DESULFURIZATION PLANT

NOx emissions are produced from the waste gas incineration process. As previously indicated, the incinerator is a regenerative type unit, and no pre-combustion controls are available that would affect NOx emission rate. However, the incinerator gas exhaust can be treated with SCR or SNCR. SCR application would require the pre-absorption of heat since the incinerator exhaust can range from 1,500 to 2,000°F. The exhaust gas would have to be lowered to a rate of at least 1,200°F to enable the use of the high temperature catalyst. A heat exchanger would need to be installed to add heat (as needed) to the exhaust gas for application of SNCR, as the gas inlet must be above at least 1,600°F.

Tail gas from the desulfurization unit is exhausted to the SCOT Plant thermal oxidizer. Thermal oxidation is considered to be the most effective means of reducing VOCs. Since the emissions are already controlled by incineration, no addition controls were reviewed.

4.4 BY-PRODUCTS PLANT

As indicated in the previous RACT analysis, the by-products plant emissions are controlled by the gas blanketing system, which controls over 98% of the VOCs. The gas blanketing system is considered to be RACT for this source.

The Light Oil Barge Loading facility is presently 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.

5.0 ECONOMIIC FEASIBILITY CONCLUSION

For those options that were identified as technically feasible for each source, a cost effectiveness (economic) analysis was performed. The analysis was based on the methods identified in the EPA OAQPS Control Cost Manual. Additionally, the evaluation was supplemented by the use of EPA specific costing that is contained in the sixth edition of the EPA Air Pollution Control Cost Manual and other technical bulletins and databases contained in the EPA Clean Air Technology Center website. Add-on control technology costing analysis methods were updated in 2003, as posted on the technology center website. Costing methodology for the QAQPS manual was based upon 1998 data. To update this costing analysis, the Chemical Engineering Plant Cost Index was used. The index values are referenced in the cost effectiveness spreadsheets, and referenced below. These indexes have previously been accepted for RACT/BACT/BART analysis. Other indices were considered, such as the Consumer Price Index, Producers Price Index, however, the Chemical Engineering Plant Cost Index was the most comprehensive fit for the collection of equipment and structures covered in this analysis. Fuel costs were based upon the equivalent of natural gas purchasing for any supplemental heat, as COG and BFG are already fully used by the USS processes. Natural gas pricing was based on the U.S. Energy Information Administrator, natural gas pricing for industrial users in Pennsylvania (latest available report). Electric costs were also based upon this reference, (See Appendix B). Costing was also supplemented by use of other published documents, such as the previously referenced Midwest States BART document for Iron and Steel Mills, as well as vendor provided information (where available). Certain items used in the analysis were based on site-specific or U.S. Steel specific information, such as the interest rate on capital, natural gas cost, and ammonia costs. Where a vendor quote was obtained, it was noted as well. Otherwise, the referenced EPA cost analysis guidance method was used.

An example of a cost effectiveness calculation is provided in Appendix C. Results of the cost effectiveness analysis for each source is provided in Table 5.1. The actual analysis costing sheets that identify the inputs are provided in Appendix D. Note again that all cost analysis were based upon the reductions that could be obtained from each technology application versus the potential to emit for each source. In all cases the potential to emit was based upon the permit limits contained in the facility Operating Permit or any more recent Installation Permits for such source.

6.0 CONCLUSION

A technical and economic re-evaluation of the application of potential emission reduction measures for NOx and VOC sources was performed for each applicable source at US Steel's Clairton Works. Technically feasible control options were identified for several sources. For these options an economical feasibility (cost effectiveness) was performed. No additional controls were considered to be economically feasible. Previous RACT requirements remain in-place, and additional changes since the previous RACT application (i.e., elimination of the ability to combust coal or fuel oils, COG consumption maximization and boiler automation) have been instituted. These changes have resulted in plant wide emission reductions. Based on this analysis, no additional control measures were considered to be RACT.

7.0 REFERENCES

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TABLES

TABLE 2-1

U.S. Steel - Clairton Plant
2014 RACT for 8-hour Ozone
NOx Control Summary

EQUIPMENT INFORMATION						Firing		Fuels		POTENTIAL NOx CONTROL METHODS											NOx Emissions Summary			
										Burner		Air					Add-On Technology		Operational					
Source ID Number	Source Description	Process Rating	Year Installed	Burner Type/Method	Number of Burners	Direct	Indirect	COG	NG	Low NOx	Ultra-Low NOx	Staged	Overfire	Recirculating	Preheated	Ambient	SCR	SNCR	Fuel Switching	Low Excess Air	Potential to Emit (tpy)	NOx Rate Limit (lb/MMBtu)	RACT Order #234 (tpy)	2012 Actual Emissions (tpy)
P001 - Coke Battery No. 1		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			549.3	-	-	168.41
	Fugitives																				-	-	-	0.26
P002 - Coke Battery No. 2		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			549.3	-	-	178.85
	Fugitives																				-	-	-	0.26
P003 - Coke Battery No. 3		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			549.3	-	-	130.77
	Fugitives																				-	-	-	0.26
	PEC System - Batteries 1, 2, & 3:																							
P050	Baghouse Stack																				-	-	-	7.69
	Traveling Hot Car																				-	-	-	7.95
	PEC Fugitives																				-	-	-	0.76
	Uncontrolled Pushing																				-	-	-	0.015
P004 - Coke Battery No. 7		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			549.3	-	-	0.00
	Fugitives																				-	-	-	0.00
P005 - Coke Battery No. 8		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			549.3	-	-	0.00
	Fugitives																				-	-	-	0.00
P006 - Coke Battery No. 9		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			549.3	-	-	0.00
	Fugitives																				-	-	-	0.00
	PEC System - Batteries 7, 8, & 9:																							
P051	Baghouse Stack																				-	-	-	0.00
	Traveling Hot Car																				-	-	-	0.00
	PEC Fugitives																				-	-	-	0.00
	Uncontrolled Pushing																				-	-	-	0.00
P007 - Coke Battery No. 13		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			307.5	-	-	119.48
	Fugitives																				-	-	-	0.32
P008 - Coke Battery No. 14		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			307.5	-	-	113.53
	Fugitives																				-	-	-	0.32
P009 - Coke Battery No. 15		517,935 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			307.5	-	-	111.82
	Fugitives																				-	-	-	0.32
	PEC System - Batteries 13, 14, & 15:																							
P052	Baghouse Stack																				-	-	-	9.48
	Traveling Hot Car																				-	-	-	9.78
	PEC Fugitives																				-	-	-	0.93
	Uncontrolled Pushing																				-	-	-	0.32

TABLE 2-1

U.S. Steel - Clairton Plant
2014 RACT for 8-hour Ozone
NOx Control Summary

EQUIPMENT INFORMATION						Firing		Fuels		POTENTIAL NOx CONTROL METHODS											NOx Emissions Summary			
										Burner		Air					Add-On Technology		Operational					
Source ID Number	Source Description	Process Rating	Year Installed	Burner Type/Method	Number of Burners	Direct	Indirect	COG	NG	Low NOx	Ultra-Low NOx	Staged	Overfire	Recirculating	Preheated	Ambient	SCR	SNCR	Fuel Switching	Low Excess Air	Potential to Emit (tpy)	NOx Rate Limit (lb/MMBtu)	RACT Order #234 (tpy)	2012 Actual Emissions (tpy)
P010 - Coke Battery No. 19		1,002,290 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			1118.7	-	-	773.45
	Fugitives																				-	-	-	0.50
P011 - Coke Battery No. 20		1,002,290 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			1118.7	-	-	500.38
	Fugitives																				-	-	-	0.60
	PEC System - Batteries 19 & 20:																							
P053	Baghouse Stack																				-	-	-	11.74
	Traveling Hot Car																				-	-	-	11.85
	PEC Fugitives																				-	-	-	1.13
	Uncontrolled Pushing																				-	-	-	0.33
P012 - Coke Battery B		1,491,025 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			820.1	-	-	361.91
	Fugitives																				-	-	-	0.98
	PEC System - Battery B:																							
P054	Baghouse Stack																				-	-	-	10.4
	Traveling Hot Car																				-	-	-	0.00
	PEC Fugitives																				-	-	-	0.62
	Uncontrolled Pushing																				-	-	-	0.00
P046 - Coke Battery C		1,379,059 tons coal/yr																						
	Combustion Stack (Underfiring)					X		X	X									X			461.2	-	-	16.98
	Fugitives																				-	-	-	0.02
	PEC System - Battery C:																							
P046	Baghouse Stack																				-	-	-	1.07
	Traveling Hot Car																				-	-	-	0.49
	PEC Fugitives																				-	-	-	0.11
	Uncontrolled Pushing																				-	-	-	0.00
P019	Desulfur. Plant (Sulfur Prod)	6,394,800 tons coke/yr				X		X	X												31.45	-	-	1.08
B001	Boiler No. 1 (Cyclone)	760 MMBTU/hr	1959	COG injected into cyclone secondary air	3		X	X	X	X	X			X			X	X			1740.00	0.54	1740	522.89
B002	Boiler No. 2 (Wall-fired)	481 MMBTU/hr	1960-61	4 wall-fired insert nozzles	4		X	X	X	X	X		X	X			X	X			1285.00	0.54	1285	100.0
B005	Boiler R1 (Wall-fired)	229 MMBTU/hr	1974	Wall-fired; Combustion air not preheated	1		X	X	X	X	X		X	X		X	X	X			525	0.54	525	11.54
B006	Boiler R2 (Wall-fired)	229 MMBTU/hr	1974	Wall-fired; Combustion air not preheated	1		X	X	X	X	X		X	X		X	X	X			525	0.54	525	10.68
B007	Boiler T1 (Wall-fired)	156 MMBTU/hr	1975	Wall-fired; Combustion air not preheated	1		X	X	X	X	X		X	X		X	X	X			358	0.54	358	11.5
B008	Boiler T2 (Wall-fired)	156 MMBTU/hr	1975	Wall-fired; Combustion air not preheated	1		X	X	X	X	X		X	X		X	X	X			358	0.54	358	10.34
B010	Ammonia Flare	12.5 MMBTU/hr				X															19.03	-	-	8.67
-	Flaring																				-	-	-	0.0049

TABLE 2-2

U.S. Steel - Clairton Plant
2014 RACT for 8-hour Ozone
VOC Control Summary

EQUIPMENT INFORMATION						Firing		Fuels		POTENTIAL VOC CONTROL METHODS Add-On Technology			VOC Emissions Summary			
Source ID Number	Source Description	Process Rating	Year Installed	Burner Type/Method	Number of Burners	Direct	Indirect	COG	NG	Incineration	Carbon Absorption	Condensation	Potential to Emit (tpy)	VOC Rate Limit (lb/MMBtu)	RACT Order #234 (tpy)	2012 Actual Emissions (tpy)
P001 - Coke Battery No. 1		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				24.3	-	-	0.89
	Fugitives												-	-	-	2.72
P002 - Coke Battery No. 2		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				24.3	-	-	0.80
	Fugitives												-	-	-	2.84
P003 - Coke Battery No. 3		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				24.3	-	-	0.29
	Fugitives												-	-	-	2.84
	PEC System - Batteries 1, 2, & 3:															
P050	Baghouse Stack												-	-	-	1.36
	Traveling Hot Car												-	-	-	0.14
	PEC Fugitives												-	-	-	0.15
	Uncontrolled Pushing												-	-	-	0.003
P013	Quench Tower No. 1 (Batteries 1, 2 & 3)												-	-	-	5.63
P004 - Coke Battery No. 7		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				24.3	-	-	0.00
	Fugitives												-	-	-	0.00
P005 - Coke Battery No. 8		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				24.3	-	-	0.00
	Fugitives												-	-	-	0.00
P006 - Coke Battery No. 9		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				24.3	-	-	0.00
	Fugitives												-	-	-	0.00
	PEC System - Batteries 7, 8, & 9:															
P051	Baghouse Stack												-	-	-	0.00
	Traveling Hot Car												-	-	-	0.00
	PEC Fugitives												-	-	-	0.00
	Uncontrolled Pushing												-	-	-	0.00
P014	Quench Tower No. 3 (Batteries 7, 8 & 9)												-	-	-	0.00
P007 - Coke Battery No. 13		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				25.7	-	-	0.57
	Fugitives												-	-	-	2.53
P008 - Coke Battery No. 14		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				25.7	-	-	0.59
	Fugitives												-	-	-	2.67
P009 - Coke Battery No. 15		517,935 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				25.7	-	-	0.21
	Fugitives												-	-	-	2.36
	PEC System - Batteries 13, 14, & 15:															
P052	Baghouse Stack												-	-	-	0.83
	Traveling Hot Car												-	-	-	0.086
	PEC Fugitives												-	-	-	0.09
	Uncontrolled Pushing												-	-	-	0.03
P015	Quench Tower No. 5 (Batteries 13, 14 & 15)												-	-	-	6.40

TABLE 2-2

U.S. Steel - Clairton Plant
2014 RACT for 8-hour Ozone
VOC Control Summary

EQUIPMENT INFORMATION						Firing		Fuels		POTENTIAL VOC CONTROL METHODS Add-On Technology			VOC Emissions Summary			
Source ID Number	Source Description	Process Rating	Year Installed	Burner Type/Method	Number of Burners	Direct	Indirect	COG	NG	Incineration	Carbon Absorption	Condensation	Potential to Emit (tpy)	VOC Rate Limit (lb/MMBtu)	RACT Order #234 (tpy)	2012 Actual Emissions (tpy)
P010 - Coke Battery No. 19		1,002,290 tons coal/yr														
	Combustion Stack (Underfiring)						X	X	X				47.1	-	-	4.14
	Fugitives												-	-	-	3.54
P011 - Coke Battery No. 20		1,002,290 tons coal/yr														
	Combustion Stack (Underfiring)						X	X	X				47.1	-	-	37.71
	Fugitives												-	-	-	3.31
	PEC System - Batteries 19 & 20:															
P053	Baghouse Stack												-	-	-	0.79
	Traveling Hot Car												-	-	-	0.08
	PEC Fugitives												-	-	-	0.09
	Uncontrolled Pushing												-	-	-	0.02
P016	Quench Tower No. 7 (Batteries 19 & 20)												-	-	-	9.7
P012 - Coke Battery B		1,491,025 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				70.1	-	-	1.31
	Fugitives												-	-	-	3.02
	PEC System - Battery B:															
P054	Baghouse Stack												-	-	-	2.66
	Traveling Hot Car												-	-	-	0
	PEC Fugitives												-	-	-	0.14
	Uncontrolled Pushing												-	-	-	0.00
P017	Quench Tower B (Battery B)												-	-	-	15.6
P046 - Coke Battery C		1,379,059 tons coal/yr														
	Combustion Stack (Underfiring)					X		X	X				5.0	-	-	0.19
	Fugitives												-	-	-	0.15
	PEC System - Battery C:															
P046	Baghouse Stack												-	-	-	0.07
	Traveling Hot Car												-	-	-	0.01
	PEC Fugitives												-	-	-	1.39
	Uncontrolled Pushing												-	-	-	0.00
P047	Quench Tower C (Battery C)												-	-	-	0.58
	SCOT Plant (Sulfur Production)												-	-	-	56.70
P019	Desulfurization Plant	6,394,800 tons coke/yr				X		X	X				398.40	-	-	
P021	Coke By-Product Recovery Plant:												124.30	-	-	
Included in P021	Methanol Tank V-400												0.013	-	-	-
	Methanol Tank V-410												0.013	-	-	-
	MEA/Methanol Tank V-430												0.359	-	-	-
	Tar/FI Decanters												-	-	-	2.00
	FI Circ./Surge Tanks												-	-	-	2.00
	Tar Storage/Sep Tanks												-	-	-	0.10
	Light Oil Collecting Tanks												-	-	-	0.41
	Final Cooler Sump												-	-	-	1.47
	FL Pumphouse Sumps												-	-	-	2.00
	Equipment Leaks/Samp Conn												-	-	-	0.0001
	Tar Collecting Tanks												-	-	-	0.01
P044	Light Oil (L.O.) Barge Loading	55,000,000 gallons/yr											0.75	-	-	0.03
B001	Boiler No. 1	760 MMBTU/hr	1959	COG injected into cyclone secondary air	3		X	X	X				18.31	-	-	5.58
B002	Boiler No. 2	481 MMBTU/hr	1960-61	4 wall-fired insert nozzles	4		X	X	X				11.59	-	-	2.57
B005	Boiler R1	229 MMBTU/hr	1974	Wall-fired; Combustion air not preheated	1		X	X	X				5.52	-	-	0.14
B006	Boiler R2	229 MMBTU/hr	1974	Wall-fired; Combustion air not preheated	1		X	X	X				5.52	-	-	0.12

TABLE 2-2

U.S. Steel - Clairton Plant
2014 RACT for 8-hour Ozone
VOC Control Summary

EQUIPMENT INFORMATION						Firing		Fuels		POTENTIAL VOC CONTROL METHODS Add-On Technology			VOC Emissions Summary			
Source ID Number	Source Description	Process Rating	Year Installed	Burner Type/Method	Number of Burners	Direct	Indirect	COG	NG	Incineration	Carbon Absorption	Condensation	Potential to Emit (tpy)	VOC Rate Limit (lb/MMBtu)	RACT Order #234 (tpy)	2012 Actual Emissions (tpy)
B007	Boiler T1	156 MMBTU/hr	1975	Wall-fired; Combustion air not preheated	1		X	X	X				3.76	-	-	0.19
B008	Boiler T2	156 MMBTU/hr	1975	Wall-fired; Combustion air not preheated	1		X	X	X				3.76	-	-	0.19
B010	Ammonia Flare	12.5 MMBTU/hr				X							0.49	-	-	0.01
-	Storage Tanks >40,000 gallons (T001-T034)												0.71	-	-	-
-	Safety-Kleen Parts Washer												-	-	-	1.65
-	Paints and Thinners												-	-	-	6.74
-	Flaring												-	-	-	0.004
-	WWTP Aeration Basins												-	-	-	1.48
-	Methanol Usage												-	-	-	2.17

TABLE 5-1

U.S. Steel - Clairton Plant
2014 RACT for 8-hour Ozone
NOx Controls Cost Effectiveness Summary Table

CONTROL TECHNOLOGY	EMISSION SOURCES			
	Boiler #1	Boiler #2	Boiler R1/R2	Boiler T1/T2
	$/ton NOx Removed			
SCR	7,560	6,901	5,993	6,669
SNCR	37,087	32,621	23,896	26,968
Low NOx Burners	See Report - Section 4.2	NA	NA	NA

APPENDIX A

Summary of RBLC Database Review

Appendix A
RBLC Search Summary - Clairton
Date Range: 1/1/2004 to 1/30/2014
Pollutant: NOx and VOC

Draft determinations are listed in italics.

Ref #	Process	Description	Permit Number	Date	State	RBLC ID	Company	Facility Information	Process	Process Description	Control	Pollutant	Emission Limits	Other Information
4	13.310	Natural Gas	503-0095-X001	8/17/2007	AL	AL-0230	ThyssenKrupp Steel and Stainless USA, LLC	New carbon and stainless steel mill, near a Class I Area, to produce various grades and/or types of steel in various forms - coils, slits, sheets, etc.	3 Natural Gas Fired boilers with UNLB & EGR	Throughput is 64.9 mmbtu/hr each, natural gas.	NOx BACT-PSD is UNLB. No control is noted for VOC BACT-PSD.	NOx VOC	0.085 lb/mmbtu ea 40.1 lb/hr ea 0.0055 lb/mmbtu ea 2.6 lb/hr ea	Emissions from the 4 natural gas fired walking beam reheat furnaces.
11	13.310	Natural Gas, includes propane and liquified petroleum gas	2062-AOP-R0	7/22/2004	AR	AR-0077	Steelcorr, Inc. Bluewater Project	New specialty steel mill producing various hot rolled, cold rolled and galvanized products for various end use markets	Boilers	Two boilers, 22 mmbtu/hr pickle line and 51 mmbtu/hr vacuum degasser	NOx BACT-PSD is LNB. VOC BACT-PSD is natural gas combustion only.	NOx VOC	0.08 lb/mmbtu 0.0055 lb/mmbtu	
14	81.390	Other Steel Foundry Processes	2062-AOP-R0	7/22/2004	AR	AR-0077	Steelcorr, Inc. Bluewater Project	New specialty steel mill producing various hot rolled, cold rolled and galvanized products for various end use markets	Degasser Hotwell Flare	Natural gas, degasser uses a flare to control CO emissions, PM emissions controlled by the hotwell.	No control is noted for NOx BACT-PSD. VOC BACT-PSD is natural gas combustion only in flare.	NOx VOC	0.01 lb/hr 1.06 lb/hr	
21	13.310	Natural Gas, includes propane and liquified petroleum gas	883-AOP-R4	6/11/2004	AR	AR-0086	Nucor-Yamato Steel Company	New Greenfield facility producing steel beams, primarily from steel scrap using EAFs.	VTD Boiler	Natural gas, 50 mmbtu/hr	NOx and VOC are not included in the listing.	NA	NA	
25	13.310	Natural Gas	1139-AOP-R6	4/3/2006	AR	AR-0090	Nucor Steel Arkansas	Scrap steel mill producing flat-rolled steel primarily from steel scrap and scrap substitutes using the EAF process. Entry is for Title V renewal and changes including roof feed to EAF, and operating restrictions on pickle line boilers.	Pickle Line Boilers, SN-52	Natural gas fired, 12.6 mmbtu/hr each.	NOx BACT-PSD is LNB. VOC BACT-PSD is good combustion practices.	NOx VOC	2.9 lb/hr 12.4 tpy 0.075 lb/mmbtu 0.2 lb/hr 0.9 tpy 0.0055 lb/mmbtu	
30	81.390	Casting & Pouring Processes	08830AOP-R6	4/5/2006	AR	AR-0091	Nucor-Yamato Steel Company	New Greenfield facility producing steel beams, primarily from steel scrap using EAFs.	Castrip VTD Boiler	Natural gas fired, no throughput specified.	NOx and VOC are not included in the listing.	NA	NA	
31	13.390	Other Gaseous Fuel & Gaseous Fuel Mixtures	1139-AOP-R9	12/12/2007	AR	AR-0095	Nucor Steel Arkansas	Scrap steel mill producing flat-rolled steel primarily from steel scrap and scrap substitutes using the EAF process.	Pickle Line Boilers (3)	Natural gas fired 12.6 mmbtu/hr (each).	NOx BACT-PSD is LNB.	NOx	0.0055 lb/mmbtu	
33	81.290	Other Steel Manufacturing Processes	1139-AOP-R9	12/12/2007	AR	AR-0095	Nucor Steel Arkansas	Scrap steel mill producing flat-rolled steel primarily from steel scrap and scrap substitutes using the EAF process.	VTD Boiler	Natural gas fired, 50.21 mmbtu/hr.	NOx BACT-PSD is ULNB.	NOx	0.035 lb/mmbtu	
42	81.100	Coke Processes	06070020	3/13/2008	IL	IL-0109	Suncoke - Gateway Energy &Coke Company	Gateway has constructed a heat recovery plant (no by-products plant) consisting of three batteries with a total of 120 ovens. The coke plant can process 1.1 million tons of coal which will produce 740,000 tons of furnace coke per year. The coke will be used at the neighboring USS plant, considered a single source ofr prupsoes of NSR. The project is significant for all pollutants except VOM and lead. A netting analysis was used to show the increases would not be significant - the decreases relied upon are from emission reduction projects at USS	Sources including charing, doors, pushing, main stack, individual waste heat stacks, quenching, and coke crushing and screening were listed.	NA	NOx and VOC were not included in any of the listings.	NA	NA	
43	81.190	Other Coke Processes	06070088	3/13/2008	IL	IL-0110	USS Granite City Works	Gateway's Coke Plant Project (IL-0109) are condisered a single source overall combined larger project for purposes of applicability of new source review regulations.	Coke Conveyor System	Conveyor system and ancillary equipment designed to move the coke from Gateway to Granite city Works	NOx and VOC were not included in the listing.	NA	NA	
48	81.115	Charging	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-101 Coke Battery 1 Coal Charging	Throughput of 197 tons/hour, maximum throughput of 1,725,720 tons per year dry coal charged.	NOx and VOC are not included in the listing.	NA	NA	
49	81.111	Pushing	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-102 Coke Battery 1 Coke Pushing	Throughput of 126 tons/hour, primary fuel is coal, maximum throughput of 1,102,311 tons per year dry coke pushed.	NOx BACT-PSD and VOC BACT-PSD are both no control.	NOx VOC	4.11 lb/hr 16.38 tons/year 0.019 lb/ton dry coke 16.67 lb/hr tons/hour 66.37 tons/year 0.077 lb/ton dry coke	
50	81.190	Other Coke Processes	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-103 Coke Battery 1 Quench Tower	182.76 tons/hour; 1.72 million tons/year	NOx and VOC are not included in the listing.	NA	NA	
51	81.112	Battery Stack	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-111-Coke Battery 1 Flue Gas Desulfurization Stack	Throughput of 197 tons/hour, primary fuel is coal, maximum throughput of 1,725,720 tons of coal per year.	NOx BACT-PSD is staged combustion in coke oven. BACT-PSD VOC is good combustion practices, no control.	NOx VOC	153.7 lb/hr 612.03 tons/hour 0.71 lb/ton wet coal 0.77 lb/hr 3.05 tons/hour 0.0035 lb/ton wet coal	
52	81.115	Charging	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-201 Coke Battery 1 Coal Charging	Throughput of 197 tons/hour, maximum throughput of 1,725,720 tons per year dry coal charged.	NOx and VOC are not included in the listing.	NA	NA	

Appendix A
RBLC Search Summary - Clairton
Date Range: 1/1/2004 to 1/30/2014
Pollutant: NOx and VOC

Draft determinations are listed in italics.

Ref #	Process	Description	Permit Number	Date	State	RBLC ID	Company	Facility Information	Process	Process Description	Control	Pollutant	Emission Limits	Other Information
53	81.111	Pushing	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-202 Coke Battery 2 Coke Pushing	Throughput of 126 tons/hour, primary fuel is coal, maximum throughput of 1,102,311 tons per year dry coke pushed.	NOx BACT-PSD and VOC BACT-PSD are both no control.	NOx VOC	4.11 lb/hr 16.38 tons/year 0.019 lb/ton dry coke 16.67 lb/hr tons/hour 66.37 tons/year 0.077 lb/ton dry coke	
54	81.190	Other Coke Processes	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-203 Coke Battery 2 Quench Tower	182.76 tons/hour; 1.72 million tons/year	NOx and VOC are not included in the listing.	NA	NA	
55	81.112	Battery Stack	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	COK-211-Coke Battery 2 Flue Gas Desulfurization Stack	Throughput of 197 tons/hour, primary fuel is coal, maximum throughput of 1,725,720 tons of coal per year.	NOx BACT-PSD is staged combustion in coke oven. BACT-PSD VOC is good combustion practices, no control.	NOx VOC	153.7 lb/hr 612.03 tons/hour 0.71 lb/ton wet coal 0.77 lb/hr 3.05 tons/hour 0.0035 lb/ton wet coal	
58	81.190	Other Coke Processes	PSD-LA-740	5/24/2010	LA	LA-0239	Nucor Steel Louisiana	Blast furnaces are used to produce pig iron with plans to reach an anticipated high of 6 million metric tonnes of iron per year	PCI-101 PCI Mill Vent	Throughput of 85.10 mmbtu/hr natural gas.	Both NOx and VOC BACT-PSD are good combustion practices, no control.	NOx VOC	5.07 lb/hr 18.27 tons/hour 0.049 lb/mmbtu 0.56 lb/hr 2.01 tons/hour	
99	13.310	Natural Gas, includes propane and liquified petroleum gas	13-04176	6/10/2004	OH	OH-0276	Charter Steel	New Melt Shop at existing facility, includes EAF, LMF, vacuum oxygen degasser, boiler, continous caseters, tundish preheaters, cooling tower, etc.	Boiler for VOD Vessel	Natural gas, 28.6 mmbtu/hr; with LNB, modified from 25 to 28.6 mmbtu/hr in administrative modification dated 2/12/08	NOx BACT-PSD is LNB. No control is listed for VOC BACT-PSD.	NOx VOC	2.8 lb/hr 12.27 tons/yr 0.15 b/hr 0.68 tons/yr	Emissions from natural gas combustion
111	81.112	Battery Stack	04-01360	6/14/2004	OH	OH-0297	US Coking Group, LLC - FDS Coke	Two nonrecovery coke oven batteries consisting of 84 ovens per battery with heat recovery steam generators	Coke Oven Batteries (2) w/168 ovens, battery stack	Coal-fired ovens, 2.06 MMT/yr, nonrecovery coke oven batteries with heat recovery steam generators. Waste gas with staged combustion.	NOx BACT-PSD is staged combustion. VOC BACT-PSD is combustion optimization.	NOx VOC	246 lb/hr 1030 tpy 12 mo roll 1 lb/ton wet coal 10.6 lb/hr 46.5 tpy 12 mo roll 10 ppmvd by vol dry	
112	81.115	Charging	04-01360	6/14/2004	OH	OH-0297	US Coking Group, LLC - FDS Coke	Two nonrecovery coke oven batteries consisting of 84 ovens per battery with heat recovery steam generators	Coke Oven Batteries (2) w/168 ovens, charging	Coal-fired ovens, 2.06 MMT/yr. Charging operations (4), with stamped coal carriers, movable hoods and stationary baghouses.	No control is noted for VOC BACT-PSD.	VOC	0.67 lb/hr 2.06 tpy 12 mo roll	
113	81.111	Pushing	04-01360	6/14/2004	OH	OH-0297	US Coking Group, LLC - FDS Coke	Two nonrecovery coke oven batteries consisting of 84 ovens per battery with heat recovery steam generators	Coke Oven Batteries (2) w/168 ovens, pushing	Coal-fired ovens, 1.44 MMT/yr. Pushing operations (4), fully enclosed flat push hot cars, w/bh vented form travel to quench tower. NOx BACT-PSD is no control. VOC BACT-PSD is work practices.	Coal-fired ovens, 1.44 MMT/yr. Pushing operations (4), fully enclosed flat push hot cars, w/bh vented form travel to quench tower. NOx BACT-PSD is no control. VOC BACT-PSD is work practices.	NOx VOC	6.4 lb/hr 20 tpy 12 mo roll 13.5 lb/hr 41 tpy 12 mo roll	
114	81.190	Other Coke Processes	04-01360	6/14/2004	OH	OH-0297	US Coking Group, LLC - FDS Coke	Two nonrecovery coke oven batteries consisting of 84 ovens per battery with heat recovery steam generators	Coke Oven Batteries (2), HRSG Bypass (6)	Coal-fired ovens, 2.06 MMT/yr. HRSG bypass vents.	No control is noted for either NOx or VOC BACT-PSD.	NOx VOC	39.2 lb/hr 22.6 tpy 12 mo roll 1.8 lb/hr 1.0 tpy 12 mo roll	
115	81.190	Other Coke Processes	04-01360	6/14/2004	OH	OH-0297	US Coking Group, LLC - FDS Coke	Two nonrecovery coke oven batteries consisting of 84 ovens per battery with heat recovery steam generators	Quench Tower (2)	Two quench towers, one for each of two batteries, controlled with internal baffles; 1.44 MMT/yr of coke from both batteries	NOx and VOC were not included in the listing.	NA	NA	
138	81.115	Charging	P0104768	2/9/2010	OH	OH-0332	Sun Coke Energy, Inc. Middletown Coke Company	New Greenfield facility, but considered one facility with AK steel due to a 20 year contract to only supply AK with coke. Heat recovery coke battery, 100 heat recovery coke ovens in 3 batteries. Includes coal handling, charging, pushing, etc. Maximum throughput 912,500 tons wet coal/year and 654,449 tons coke/yr, 2690 tons coke/day. Waste gas flow 50,000 scfm. All power sent to AK Steel through grid.	Charging, Coke Oven Batteries (3) with 100 heat recovery coke ovens	Operational restrictions include maximum hourly charging and pushing rates. LAER review for PM2.5, SO2, and NOx; BACT review for PM, PM10, CO, SO2, and NOx.	No control is noted for VOC.	VOC	1.0 lb/hr 0.91 tpy 12 mo roll	
139	81.190	Other Coke Processes	P0104768	2/9/2010	OH	OH-0332	Sun Coke Energy, Inc. Middletown Coke Company	New Greenfield facility, but considered one facility with AK steel due to a 20 year contract to only supply AK with coke. Heat recovery coke battery, 100 heat recovery coke ovens in 3 batteries. Includes coal handling, charging, pushing, etc. Maximum throughput 912,500 tons wet coal/year and 654,449 tons coke/yr, 2690 tons coke/day. Waste gas flow 50,000 scfm. All power sent to AK Steel through grid.	Coke Oven Batteries (3) bypass lime spray dryer/BH for maintenance	Operational restrictions include maximum hourly charging and pushing rates. LAER review for PM2.5, SO2, and NOx; BACT review for PM, PM10, CO, SO2, and NOx. Main stack, coking with HRSG when bypassing the lime spray dryer/BH for inspection/maintenance.	NOx LAER is none - bypass control. VOC is bypass control.	NOx VOC	1 lb/ton coal w/spray dryer filter bypass 6.25 tpy 12 mo roll sum 0.28 tpy 12 mo roll sum	Restricted to 120 hours/year

Appendix A
RBLC Search Summary - Clairton
Date Range: 1/1/2004 to 1/30/2014
Pollutant: NOx and VOC

Draft determinations are listed in italics.

Ref #	Process	Description	Permit Number	Date	State	RBLC ID	Company	Facility Information	Process	Process Description	Control	Pollutant	Emission Limits	Other Information
140	81.112	Battery Stack	P0104768	2/9/2010	OH	OH-0332	Sun Coke Energy, Inc. Middletown Coke Company	New Greenfield facility, but considered one facility with AK steel due to a 20 year contract to only supply AK with coke. Heat recovery coke battery, 100 heat recovery coke ovens in 3 batteries. Includes coal handling, charging, pushing, etc. Maximum throughput 912,500 tons wet coal/year and 654,449 tons coke/yr, 2690 tons coke/day. Waste gas flow 50,000 scfm. All power sent to AK Steel through grid.	Coke Oven Batteries (3) with 100 heat recovery coke ovens	Operational restrictions include maximum hourly charging and pushing rates. LAER review for PM2.5, SO2, and NOx; BACT review for PM, PM10, CO, SO2, and NOx. Main stack, coking with HRSG and lime spray dryer. Minimum common duct T of 1400F.	NOx LAER is staged combustion. No control is noted for VOC.	NOx VOC	104.2 lb/hr 456.25 tpy 12 mo roll 1 lb/ton wet ton of coal (LAER) 4.67 lb/hr 20.47 tpy 10 ppm emission rate from stack test similar source	
141	81.112	Battery Stack	P0104768	2/9/2010	OH	OH-0332	Sun Coke Energy, Inc. Middletown Coke Company	New Greenfield facility, but considered one facility with AK steel due to a 20 year contract to only supply AK with coke. Heat recovery coke battery, 100 heat recovery coke ovens in 3 batteries. Includes coal handling, charging, pushing, etc. Maximum throughput 912,500 tons wet coal/year and 654,449 tons coke/yr, 2690 tons coke/day. Waste gas flow 50,000 scfm. All power sent to AK Steel through grid.	Coke Oven Batteries (3) without heat recovery	Operational restrictions include maximum hourly charging and pushing rates. LAER review for PM2.5, SO2, and NOx; BACT review for PM, PM10, CO, SO2, and NOx. Coking operations without HSRG.	NOx LAER is none - bypass one HRSG at a time, one stack. VOC is the same, although not LAER.	NOx VOC	20.8 lb/hr 10 tpy 12 mo roll 1 lb NOx/ton coal 0.93 lb/hr 0.45 tpy 12 mo roll	Restricted to 960 stack hours per rolling 12 months, not including maintenance of spray dryer/BH; O&M Plan w/monthly inspections
142	81.111	Pushing	P0104768	2/9/2010	OH	OH-0332	Sun Coke Energy, Inc. Middletown Coke Company	New Greenfield facility, but considered one facility with AK steel due to a 20 year contract to only supply AK with coke. Heat recovery coke battery, 100 heat recovery coke ovens in 3 batteries. Includes coal handling, charging, pushing, etc. Maximum throughput 912,500 tons wet coal/year and 654,449 tons coke/yr, 2690 tons coke/day. Waste gas flow 50,000 scfm. All power sent to AK Steel through grid.	Pushing, Coke Oven Batteries (3) with 100 heat recovery coke ovens	Operational restrictions include maximum hourly charging and pushing rates. LAER review for PM2.5, SO2, and NOx; BACT review for PM, PM10, CO, SO2, and NOx.	NOx LAER is work practices, MACT is also applicable. No control is noted for VOC.	NOx VOC	9.5 lb/hr 8.67 tpy 12 mo roll sum 0.019 lb/ton coal charged 10 lb/hr 9.13 tpy	
143	81.190	Other Coke Processes	P0104768	2/9/2010	OH	OH-0332	Sun Coke Energy, Inc. Middletown Coke Company	New Greenfield facility, but considered one facility with AK steel due to a 20 year contract to only supply AK with coke. Heat recovery coke battery, 100 heat recovery coke ovens in 3 batteries. Includes coal handling, charging, pushing, etc. Maximum throughput 912,500 tons wet coal/year and 654,449 tons coke/yr, 2690 tons coke/day. Waste gas flow 50,000 scfm. All power sent to AK Steel through grid.	Quench Tower	Wet system with baffled tower. Interior baffle system with baffle plates that allow no more than 5% of the cross sectional area of the tower to be uncovered; water with controlled TDS.	NOx and VOC were not included in the listing.	NA	NA	
160	19.600	Misc. Boilers, Furnaces, Heaters	0059-I008	2/16/2010	PA	PA-0274	Allegheny Ludlum Corporation - Brackenridge Facility	Two EAFs, AOD vessel that feeds a continuous caster, 6-stand hot strip mill, etc. New equipment will replace older equipment which will be shut down as part of the project.	Active Heat Panel (S-205)	Natural gas fired, 60 mmbtu/hr	NOx and VOC BACT-PSD is effective combustion and operational control practices to minimize emissions	NOx VOC	0.097 lb/mmbtu 0.0053 lb/mmbtu	Hourly and annual natural gas input limits
165	81.290	Other Steel Manufacturing Processes	*10-00001*	*3/11/2005*	*PA*	*PA-0284*	*AK Steel Corp/Butler Works*	*Manufacturer of rolled electrical and stainless steel as well as a supplier of stainless semi-finished slabs - new Greenfield facility.*	*Boiler 21 (HTP)*	*Boiler is 16.34 MCF/hr and only fired on natural gas, propane, or liquefied propane or No. 2 fuel oil.*	*No control was listed for BACT-PSD for NOx.*	*NOx*	*30 ppmvd@3% O2 (gas)* *90 ppmvd@3% O2 (No. 2 fuel oil)*	
166	81.290	Other Steel Manufacturing Processes	*10-00001*	*3/11/2005*	*PA*	*PA-0284*	*AK Steel Corp/Butler Works*	*Manufacturer of rolled electrical and stainless steel as well as a supplier of stainless semi-finished slabs - new Greenfield facility.*	*Boilers 15 (MTS), Boilers 13/14 (SS), Boiler 9 (MP), Boiler 10 (MP), Boiler 11 (MP)*	*All boilers combust natural gas and range between 21 and 69 MCF/hr.*	*NOx and VOC were not included in any of the listings.*	*NA*	*NA*	
173	81.290	Other Steel Manufacturing Processes	0420-0060-DO	5/5/2008	SC	SC-0112	Nucor Steel Berkley	Add new processes and modify processes; located less than 100 km from a Class I Area.	Vacuum Degasser Boiler	Natural gas fired, 50.21 mmbtu/hr.	NOx BACT-PSD is ULNB. VOC BACT-PSD is natural gas combustion with good combustion practices.	NOx VOC	0.035 lb/mmbtu 1.76 lb/hr 0.0026 lb/mmbtu	
192	12.300	Gaseous Fuel & Gaseous Fuel Mixtures	PSDTX1188	4/19/2010	TX	TX-0576	TPCO America Inc. Pipe Manufacturing Steel Mini Mill	New Greenfield facility that converts scrap steel into seamless pipe	Vacuum Degasser Boiler	Natural gas, 40 mmbtu/hr	Both NOx and VOC BACT-PSD is good combustion practice.	NOx VOC	0.1 lb/mmbtu 0.0054 lb/mmbtu	

APPENDIX B

U.S. Energy Information Administrator Reports

Table 22. Average price of natural gas sold to industrial consumers, by state, 2011-2013
(dollars per thousand cubic feet)

State	2013 11-Month YTD	2012 11-Month YTD	2011 11-Month YTD	November	October	September	August	2013 July
Alabama	4.98	4.29	5.65	5.01	4.69	4.48	4.52	4.82
Alaska	NA	4.95	3.89	7.54	7.60	7.52	7.68	8.31
Arizona	6.31	5.75	6.96	6.30	6.60	7.04	6.74	6.30
Arkansas	6.66	6.34	7.47	6.38	7.06	6.79	6.67	6.79
California	NA	5.68	7.06	6.46	6.10	6.20	6.61	6.80
Colorado	5.78	5.87	6.37	5.48	6.64	7.18	7.33	7.35
Connecticut	NA	8.59	9.10	5.99	6.19	6.14	6.06	6.50
Delaware	NA	11.61	11.72	11.08	11.25	11.05	11.96	NA
District of Columbia	--	--	--	--	--	--	--	--
Florida	NA	7.03	8.09	6.27	6.85	6.39	6.49	7.24
Georgia	5.24	4.52	5.93	5.28	4.86	4.96	4.95	5.29
Hawaii	28.05	30.94	29.67	27.04	27.19	30.41	26.19	25.84
Idaho	NA	5.77	6.35	6.01	NA	5.05	4.96	5.27
Illinois	5.98	5.57	6.90	5.53	5.95	6.06	7.83	7.39
Indiana	NA	6.28	6.70	5.65	5.18	5.92	5.81	7.03
Iowa	NA	4.57	5.81	5.35	NA	4.79	4.64	4.65
Kansas	4.85	3.91	5.26	5.56	5.03	4.31	4.54	4.79
Kentucky	4.93	3.86	5.19	5.24	4.99	5.07	4.68	4.82
Louisiana	3.88	2.89	4.34	3.76	3.79	3.80	3.67	3.89
Maine	NA	10.03	10.75	9.31	8.09	8.37	8.59	9.08
Maryland	NA	8.17	8.59	7.94	NA	NA	NA	NA
Massachusetts	NA	9.74	10.31	NA	7.70	8.10	9.69	8.64
Michigan	6.94	7.43	8.36	6.65	6.68	7.15	7.02	7.65
Minnesota	5.03	4.41	5.57	5.46	5.02	5.07	5.14	5.68
Mississippi	NA	4.77	5.88	NA	7.08	6.99	6.24	6.66
Missouri	NA	7.95	8.57	7.38	NA	7.61	7.41	NA
Montana	7.47	7.55	8.10	7.03	7.12	6.77	6.41	7.91
Nebraska	NA	4.27	5.65	4.76	4.35	NA	NA	5.11
Nevada	6.51	7.56	9.19	7.02	7.08	6.82	7.08	6.83
New Hampshire	NA	10.54	11.63	9.60	NA	NA	11.79	11.56
New Jersey	NA	7.75	9.36	8.42	8.89	8.62	9.52	8.88
New Mexico	5.55	4.80	6.22	5.96	5.91	5.47	5.41	5.61
New York	NA	6.88	8.28	7.80	8.00	7.45	7.16	7.64
North Carolina	NA	6.33	7.72	7.33	7.02	7.12	7.29	7.30
North Dakota	4.13	4.47	5.13	4.19	3.92	3.77	3.86	4.64
Ohio	5.34	5.53	6.89	5.34	6.48	5.77	5.47	5.94
Oklahoma	NA	7.62	7.39	8.90	NA	NA	NA	9.86
Oregon	5.72	5.92	6.86	6.09	5.55	5.80	5.83	5.64
Pennsylvania	NA	9.63	9.83	9.28	9.43	8.84	9.84	NA
Rhode Island	NA	10.11	11.05	9.52	NA	8.49	--	NA
South Carolina	5.31	4.21	5.65	5.37	5.06	5.12	4.99	5.29
South Dakota	NA	5.25	6.29	5.34	NA	6.11	6.27	6.46
Tennessee	5.68	4.87	6.18	5.65	5.43	5.39	5.37	5.59
Texas	3.91	2.93	4.29	3.84	3.76	3.81	3.78	3.91
Utah	5.29	4.64	5.52	5.04	5.00	5.11	5.06	5.48
Vermont	4.97	4.87	6.19	5.20	5.14	4.68	4.73	4.91
Virginia	NA	5.30	6.48	5.86	6.05	6.40	6.29	6.72
Washington	NA	8.92	9.53	8.00	NA	9.12	9.29	8.23
West Virginia	3.53	3.57	4.96	3.42	3.55	3.64	3.43	3.37
Wisconsin	5.93	5.70	7.07	6.11	4.98	5.02	5.13	5.36
Wyoming	NA	4.77	5.60	NA	NA	NA	NA	NA
Total	**4.62**	**3.80**	**5.18**	**4.63**	**4.39**	**4.38**	**4.34**	**4.50**

See footnotes at end of table.

Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2013 and 2012 (Cents per Kilowatthour)

	Residential		Commercial		Industrial		Transportation		All Sectors	
Census Division and State	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD
New England	16.20	15.71	14.08	13.68	12.17	11.83	9.17	6.68	14.48	14.02
Connecticut	17.58	17.34	14.64	14.65	12.68	12.67	10.31	9.69	15.68	15.54
Maine	14.35	14.66	11.72	11.53	8.32	7.98	--	--	11.87	11.81
Massachusetts	15.73	14.91	14.51	13.84	13.09	12.57	NM	4.91	14.51	13.79
New Hampshire	16.36	16.07	13.52	13.36	11.41	11.83	--	--	14.31	14.19
Rhode Island	15.47	14.40	13.08	11.87	11.87	10.68	13.00	8.28	13.91	12.74
Vermont	17.15	17.01	14.64	14.32	10.19	9.98	--	--	14.46	14.22
Middle Atlantic	15.72	15.27	13.00	12.97	7.25	7.49	12.17	12.50	12.90	12.75
New Jersey	15.72	15.78	12.80	12.78	10.71	10.52	10.43	9.77	13.70	13.68
New York	18.84	17.62	15.23	15.06	6.29	6.70	13.63	14.20	15.62	15.15
Pennsylvania	12.82	12.75	9.26	9.44	7.00	7.23	7.82	8.07	9.83	9.91
East North Central	12.01	12.05	9.51	9.46	6.57	6.51	5.71	6.33	9.33	9.27
Illinois	10.25	11.37	7.88	7.99	5.73	5.80	5.44	6.15	7.99	8.40
Indiana	10.84	10.53	9.46	9.14	6.59	6.34	9.87	9.56	8.63	8.29
Michigan	14.59	14.13	11.07	10.93	7.78	7.62	9.92	8.08	11.26	10.98
Ohio	11.91	11.76	9.38	9.47	6.10	6.24	6.61	6.98	9.16	9.12
Wisconsin	13.70	13.19	10.84	10.51	7.54	7.34	--	--	10.64	10.28
West North Central	10.95	10.59	8.95	8.48	6.60	6.28	8.78	7.72	8.96	8.54
Iowa	11.15	10.82	8.47	8.01	5.66	5.30	--	--	8.12	7.71
Kansas	11.56	11.24	9.54	9.24	7.07	7.09	--	--	9.57	9.33
Minnesota	11.94	11.35	9.53	8.84	7.06	6.54	9.79	8.67	9.52	8.86
Missouri	10.52	10.17	8.72	8.20	6.14	5.89	7.90	6.97	8.96	8.53
Nebraska	10.31	10.04	8.62	8.38	7.22	7.01	--	--	8.69	8.37
North Dakota	9.10	9.06	8.31	8.02	7.20	6.55	--	--	8.19	7.83
South Dakota	10.26	10.07	8.44	8.10	6.93	6.57	--	--	8.83	8.49
South Atlantic	11.37	11.38	9.39	9.37	6.48	6.55	8.66	8.44	9.73	9.73
Delaware	13.01	13.58	10.26	10.13	8.50	8.36	--	--	10.98	11.06
District of Columbia	12.56	12.28	11.93	12.02	5.89	5.46	9.58	9.01	11.85	11.85
Florida	11.36	11.42	9.49	9.66	7.68	8.04	8.69	8.45	10.30	10.44
Georgia	11.24	11.17	9.84	9.58	6.11	5.98	8.03	7.65	9.53	9.37
Maryland	13.24	12.84	10.70	10.43	8.36	8.09	8.48	8.29	11.65	11.28
North Carolina	10.91	10.91	8.73	8.66	6.34	6.42	7.94	7.88	9.18	9.15
South Carolina	11.82	11.77	9.82	9.63	5.92	6.02	--	--	9.14	9.10
Virginia	10.93	11.08	8.05	8.08	6.65	6.72	8.17	8.51	9.01	9.07
West Virginia	9.52	9.85	8.16	8.42	6.20	6.33	8.68	8.66	7.91	8.14
East South Central	10.42	10.32	9.82	9.87	5.96	6.11	11.46	11.28	8.71	8.58
Alabama	11.27	11.40	10.50	10.63	5.99	6.22	--	--	9.02	9.18
Kentucky	9.71	9.43	8.50	8.73	5.40	5.35	--	--	7.54	7.26
Mississippi	10.82	10.26	10.21	9.33	6.45	6.24	--	--	9.15	8.60
Tennessee	10.04	10.10	10.01	10.31	6.44	7.08	11.46	11.28	9.22	9.27
West South Central	10.73	10.30	8.11	7.99	5.86	5.39	10.02	10.30	8.47	8.11
Arkansas	9.51	9.30	7.98	7.71	5.88	5.76	NM	11.23	7.82	7.62
Louisiana	9.39	8.37	8.94	7.75	5.89	4.76	9.45	8.72	8.00	6.90
Oklahoma	9.62	9.51	7.71	7.32	5.34	5.09	--	--	7.81	7.54
Texas	11.37	10.98	8.03	8.16	5.93	5.57	10.12	10.54	8.77	8.55
Mountain	11.32	10.94	9.37	8.99	6.46	6.18	10.47	9.62	9.18	8.82
Arizona	11.74	11.29	9.87	9.53	6.69	6.53	--	--	10.16	9.81
Colorado	11.87	11.46	9.87	9.39	7.22	6.95	10.55	9.69	9.80	9.39
Idaho	9.37	8.67	7.40	6.86	6.12	5.48	--	--	7.61	6.92
Montana	10.38	10.08	9.52	9.13	5.37	5.10	--	--	8.58	8.25
Nevada	11.89	11.83	9.02	8.83	6.52	6.48	8.47	8.40	9.04	8.95
New Mexico	11.69	11.37	9.78	9.32	6.32	5.83	--	--	9.24	8.83
Utah	10.42	9.93	8.37	8.06	5.88	5.62	10.68	9.79	8.18	7.84
Wyoming	10.18	9.85	8.60	8.24	6.41	6.03	--	--	7.55	7.19
Pacific Contiguous	13.60	12.94	12.77	11.92	8.20	7.78	7.72	7.21	12.07	11.38
California	16.39	15.34	14.57	13.41	11.17	10.49	7.68	7.17	14.57	13.53
Oregon	9.94	9.80	8.39	8.31	5.86	5.59	8.88	8.24	8.39	8.21
Washington	8.67	8.53	7.76	7.68	4.22	4.13	8.29	8.06	7.06	6.94
Pacific Noncontiguous	28.59	28.76	25.52	25.50	26.08	26.99	--	--	26.61	26.96
Alaska	18.19	17.88	15.62	14.93	15.77	16.82	--	--	16.52	16.33
Hawaii	36.99	37.34	34.06	34.88	29.87	30.82	--	--	33.27	34.04
U.S. Total	12.12	11.88	10.29	10.09	6.82	6.67	10.28	10.21	10.08	9.84

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.
Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Notes: - See Glossary for definitions. - Values for 2012 are final. Values for 2013 are preliminary estimates based on a cutoff model sample.
See Technical Notes for a discussion of the sample design for the Form EIA-826.
Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.
Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.
Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report.

APPENDIX C

Sample Cost Analysis Detail Sheet

U.S. Steel - Clairton
2006 RACT for 8-hour Ozone
Controls Cost Effectivness Evaluation Example Calculation for
SNCR Technology
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

COMPANY: U.S. Steel, Clairton, PA
Source: Example
NO_X Emission Control Option: SNCR

Calculations based on Section 4.2 Chapter 1 of the EPA Air Pollution Control Cost Manual - Sixth Edition

Site Information

Utility Unit Costs

Electricity, $/kwh	At cost
Interest Rate, i %	i
Water, $/1,000 gal	At cost
BFG, $/MMBtu	At cost
COG, $/MMBtu	At cost
NG, $/MMBtu	At cost

Operating Labor, $/man-hr	At cost
Man hrs per year	
Sales Tax, % of FOB	Included in DC
Freight & Ins to Site, % of FOB	Included in DC
(a) Maintenance (Materials + Labor) % TCI	1.5%
(b) General Facilities, % DC	5%
(c) Engineering and Home Office Fees % DC	10%
(d) Process Contingency % DC	5%
(e) Project Contingency % DC+IC	15%
(f) Preproduction Costs % of D+E	2%

Source Emission Information

Equipment Life, **n** (yrs)	n
Operating Hours Per Year	hrs/yr

Control Technology Information

Boiler Fuel Rating, Q_B (mmBTU/hr)	As rated
NOX Removal Efficiency, η_{NOx}	η_{NOx}

Incremental Utility Requirements

Electricity, kw	At cost
[1]Reagent sol, gal/hr	At cost
Water, 1,000 gal/hr	At cost
BFG, MMBtu/hr	At cost
COG, MMBtu/hr	At cost
NG, MMBtu/hr	At cost

Reagent Volume, gallons = Reagent solution flow rate, gal/hr x 24 hrs/day x 14 days/2 weeks x 52 weeks/yr

Reagent Cost, $/gallon: At cost

U.S. Steel - Clairton
2006 RACT for 8-hour Ozone
Controls Cost Effectivness Evaluation Example Calculation for
SNCR Technology
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

COMPANY: U.S. Steel, Clairton, PA
Source: Example
NO_X Emission Control Option: SNCR
Calculations based on Section 4.2 Chapter 1 of the EPA Air Pollution Control Cost Manual - Sixth Edition

TOTAL CAPITAL INVESTMENT

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

Auxiliary Equipment (Heat Exchanger) At Cost

Total Indirect Capital Costs:
Indirect Installation, **IC** =DC x (b+c+d)
Project Contingency, **C** =(DC+IC) x e

Total Plant Cost, **D** =DC + IC + C

Allowance for Funds During Constr., **E** Assumed zero
Royalty Allowance, **F** Assumed zero
Preproduction Costs, **G** = (D + E) x f
Inventory Capital, **H** =Reagent vol, gal x $/gal
Initial Catalyst and Chemicals, **I** Assumed zero

TOTAL CAPITAL INVESTMENT, TCI = (D+E+F+G+H+I)

TOTAL ANNUAL COST

Direct Annual Costs
Operating & Supervisory Labor At cost
Maintenance =TCI x a
Reagent Consumption =gal/hr x 8760 hr/yr x $/gal
Utilities =kw x $/kwh x hrs/yr
Water Consumption =1,000 gal/hr x $/1,000 gal x hrs/yr
Add'l Fuel Usage (Process related) =$/MMBtu x MMBtu/hr x hrs/yr
Auxiliary Equipment Requirements =$/MMBtu x MMBtu/scf flue gas x scf flue gas/hr x hrs/yr
(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)

Total Direct Annual Costs =Sum all Direct Annual Costs

Indirect Annual Costs, IDAC
CRF $=[i(1+i)^n/(1+i)^n]-1$
Total IDAC = CRF x TCI

TOTAL ANNUAL COST, TAC = DAC + IDAC

COST EFFECTIVENESS

NOX_{in}, lbs/MMBtu
Efficiency, % η_{NOX}
Boiler Heat Input, MMBtu/hr
Total Operating Time, hrs/yr

NO_X removed, tpy $=NOX_{in} \times \eta_{NOX}$

Cost Efficiency
=TAC, $/tons NO_X removed

APPENDIX D

Cost Analysis Detail Sheets

United States Steel
RACT Analysis for NOx - Clairton
Screening Calculation: Best Case NOX Removal with SCR, Flue Gas Heating Cost Only

lbs NOX/MMcf Natural Gas: 140

Heat Capacity Boiler Combustion Stack Gas

	BOILER #1		BOILER #2		BOILER #R1/R2		BOILER #T1/T2	
	Flue Gas Composition	Heat Capacity (Btu/ft³/°F)	Flue Gas Composition	Heat Capacity (Btu/ft³/°F)	Flue Gas Composition	Heat Capacity (Btu/ft³/°F)	Flue Gas Composition	Heat Capacity (Btu/ft³/°F)
H20	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
CO2	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
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	BOILER #1	BOILER #2	BOILER #R1/R2	BOILER #T1/T2
Flow (1)	182,000 scfm	101,000 scfm	33,600 scfm	25,800 scfm
Flow	**1.09E+07 scfh**	**6.06E+06 scfh**	**2.02E+06 scfh**	**1.55E+06 scfh**
$Temperature_{SCR\ in}$ (1)	**316 F**	**327 F**	**316 F**	**316 F**
$Temperature_{SCR\ out}$ (2)	**650 F**	**650 F**	**650 F**	**650 F**
ΔT	**334 F**	**323 F**	**334 F**	**334 F**
Heat Requirement	6.4 Btu/scf	6.2 Btu/scf	6.4 Btu/scf	6.4 Btu/scf
Uncontrolled NOX (1), (3)	12,718.6 ppmv	8,049.5 ppmv	3,832.3 ppmv	2,610.7 ppmv
Uncontrolled NOX (3)	410.40 Lb / Hr	259.74 Lb / Hr	123.66 Lb / Hr	84.24 Lb / Hr
NOX control eff'y (2)	80%	80%	80%	80%
NOX Removed	328.3 Lb / Hr	207.8 Lb / Hr	98.9 Lb / Hr	67.4 Lb / Hr
NOX Removed	3.01E-05 Lb / scf flue gas	3.43E-05 Lb / scf flue gas	4.91E-05 Lb / scf flue gas	4.35E-05 Lb / scf flue gas
NOX from Natural Gas Combustion (4)	1.12E-06 Lb / scf flue gas	1.08E-06 Lb / scf flue gas	0.00E+00 Lb / scf flue gas	0.00E+00 Lb / scf flue gas
Net NOX Reduction	2.90E-05 Lb / scf flue gas	3.32E-05 Lb / scf flue gas	4.91E-05 Lb / scf flue gas	4.35E-05 Lb / scf flue gas
Natural Gas Eff'y	80.0%	80.0%	80.0%	80.0%
Natural Gas Req'd	8.0 Btu / scf flue gas	7.7 Btu / scf flue gas	8.0 Btu / scf flue gas	8.0 Btu / scf flue gas
Natural Gas Req'd	7.97E-06 MMBtu/scf flue gas	7.71E-06 MMBtu/scf flue gas	7.97E-06 MMBtu/scf flue gas	7.97E-06 MMBtu/scf flue gas
Natural Gas Cost (5)	$9.44 / MMbtu	$9.44 / MMbtu	$9.44 / MMbtu	$9.44 / MMbtu
Natural Gas Cost	$2.60 / Lb NOX Removed	$2.19 / Lb NOX Removed	$1.53 / Lb NOX Removed	$1.73 / Lb NOX Removed
Natural Gas Cost	**$5,198 / Ton NOX Removed**	**$4,382 / Ton NOX Removed**	**$3,067 / Ton NOX Removed**	**$3,457 / Ton NOX Removed**
Annual Natural Gas Cost (6)	$7,197,914	$3,862,893	$1,328,846	$1,020,364

User inputs used in calculations

(1) Average of the latest stack test data for flow 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 8760 hrs/yr.
(4) Based on 140 lb NOX per MMscf natural gas.
(5) Average utility gas rate, 2013, from US Bureau of Labor Statistics (www.bls.gov) for Pennsylvania Industrial Consumers.
(6) Annual NG Cost = $/MMBtu NG x MMBtu/scf flue gas x scf flue gas/hr x 8760 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.

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

$$CF_{Boiler\#1_1} = \frac{Actual_{2012}, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012}$	467.5	MMBtu/hr
Potential	760	MMBtu/hr
$CFBoiler\#1_1$=	0.62	

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

t_{SCR}	365	days/yr
CF_{SCR}=	1.00	
CF_{total}=	0.62	

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	80%	
Stack NO_X =	0.108	lb/MMBtu (Estimated)

Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent NH2 injected}}{\text{mole of uncontrolled } NO_X}$$

The value for ASR in a typical SCR system is approximately = 1.05

Normalized Stoichiometric Ratio, NSR

NSR = ASR X SR_1

(As per pg. 1-24 of SCR manual)

SR_1 = 1 (Ratio of equivalent moles of NH_3 per mole of reagent injected.)

NSR = 1.05

Flue Gas Flow Rate, $q_{fluegas}$

$q_{fluegas}$ = 273,000 acfm - based on testing at boilers

Space Velocity and Area Velocity, V_{space} & V_{area} Vanadium (V2O5)Catalyst on honeycomb substract with average pitch assumed

$Vol_{reactor}$ =	0.02	ft^3/cfm			
$Vol_{reactor}$ =	5460	ft^3			
$Area_{reactor}$ =	0.005	ft^2/cfm			
$Area_{reactor}$ =	1365	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, $Vol_{catalyst}$ pg 2-36 of SCR manual

$$Vol_{catalyst} = \frac{-\left(q_{flue\,gas} \times \ln\left[1-\left(\frac{\eta_{NO_x}}{ASR}\right)\right]\right)}{K_{catalyst} \times A_{specific}}$$

$Vol_{catalyst} = Vol_{reactor}$ 5460

SCR Reactor Dimensions

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

$A_{catalyst}$ =	284.4	ft^2
$A_{SCR} = 1.15 \times A_{catalyst}$		
A_{SCR} =	327.0	ft^2
l_{scr} =	18.1	ft
w_{scr} =	18.1	ft

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

h'_{layer} =	3.1	ft (nominal hegiht as per pg. 2-38 of SCR manual)
n_{layer} =	6.2	(There must be at least two catalyst layers, pg. 2-38 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 pracitce)
c_2 =	9	
h_{SCR} =	88.8	

Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times NSR \times \eta_{NO_x} \times M_{reagent}}{M_{NO_x} \times SR_f}$$

NOx_{in} =	0.54	lb/MMBtu
Q_B =	760	MMBtu/hr
NSR =	1.05	
η_{NO_x} =	80%	
$M_{reagent}$ =	17.03	grams NH_3/mole
M_{NOx} =	46.01	grams NO_2/mole
SR_f =	1	(Ratio of equivalent moles of NH_3 per mole of reagent injected.)
$\dot{m}_{reagent}$ =	127.6	lbs/hr

For ammonia,

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

C_{sol} =	29%		(Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)
$\dot{m}_{sol}$ =	440.0	lbs/hr	

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

r_{sol} =	56	lb/ft^3	(For a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)
v_{sol} =	7.481	gal/ft^3	(Specific volume of a 20% solution ammonia at 60°F, pg. 2-40 of SCR manual)
q_{sol} =	58.8	gph	

Tank volume;

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol_{Tank} =	19750	gallons	

TOTAL CAPITAL INVESTMENT, TCI

Assumptions:

- High-dust SCR system
- 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.
- Costs for the tail-end arrangement cannot be estimated here because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements.

Cost Year = 2014

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.

DC= Direct Capital costs includes PEC such as SCR 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

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Total Direct Capital Costs, DC, equations noted in 1998 dollars, TDC corrected below:

$$DC = Q_B\left[\frac{\$3{,}380}{MMBtu/hr} + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)\right]$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[\frac{\$6.12}{ft - MMBTu/hr}\, h_{SCR}\right] - \frac{\$187.9}{MMBtu/hr}$$

$f(h_{SCR})$ = 356

Adjustment for the ammonia flow rate:

$$f(NH_3rate) = \left[\frac{\$411}{lb/hr}\,\frac{m_{NH3,req,ss}}{Q_B}\right] - \frac{\$47.3}{MMBtu/hr}$$

$f(NH_3rate)$ = $ 21.70

For a retrofit:

f(new) = $ - per MMBut/hr

For a new boiler:

f(new) = $ (728) per MMBut/hr

Adjustmnent for installing an SCR bypass:

f(bypass) = $ - per MMBut/hr (if no bypass installed)
f(bypass) = $ 127 per MMBut/hr (if bypass installed)

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst}CC_{initial}$$

$Vol_{catalyst}$ = $ 5,460.00 ft^3
$CC_{initial}$ = $ 240 per ft^3 (Cost of initial catalyst:current estimation for a ceramic honeycomb catalyst)
$f(Vol_{catalyst})$ = 1310400

Direct Capital, DC = $ 9,364,301 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs

Average values of indirect installation factors are applied to the direct capital cost estimate to obtain values for indirect installation costs. These costs are estimated as a percentage of the TCI.

Total Indirect Installation Costs, IC =	$	1,872,860	
=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 =		1685574.228	
=		15%	of DC + IC
Total Plant Cost, D =	$	12,922,735.75	= DC + IC + C
Allowance for Funds During Construction, E =	$	-	(Assumed zero for SCR)
Royalty Allowance,F =	$	-	(Assumed zero for SCR)
Preproduction Costs, G =	$	258,454.71	
=		2%	of D + E
Inventory Capital, H =	$	43,449.49	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ =		19750	gal/yr
$Cost_{reagent}$ =		2.2	$/gal (Mundi Index, Spot Market, January 2014)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SCR)
Total Capital Investment, TCI =	$	13,224,639.95	= D + E + F + G + H + I

TOTAL ANNUAL COSTS

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

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

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

Maintenance:

1.5%	of TCI		
Maintenance =	$	198,370	
Total operating time, t_{op} = CF_{total} x 8760 hrs/yr		8760	hours (CF not used as max hours required for RACT analysis)

Reagent Consumption:

$cost_{reagent}$		2.2	$/gallon
Annual reagent cost =	$	1,132,790	= $q_{reagent}$ x $cost_{reagent}$ x t_{op}

Utilities:

$$Power = 0.105 Q_n \left[NO_{in} \eta_{NO_x} + 0.5 \left(\Delta P_{duct} + n_{catalyst} \Delta P_{catalyst} \right) \right]$$

DP_{duct} =	2	inches water (Typical values as per pg. 2-46 of SCR manual)
$DP_{catalyst}$ =	0.75	inches water (Typical values as per pg. 2-46 of ScR manual)
Power =	329.5	
$Cost_{elec}$ =	0.07	$/kwh
t_{op} =	8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	$ 202,074	

Additional Energy Requirement = $ 7,197,914 (Additional heating of exhaust gas required for SCR operations.)

Catalyst Replacement:

Catalyst Replacement Cost = n_{SCR} x $Vol_{catalyst}$ x ($CC_{replace}/R_{layer}$)

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)
Catallyst Replacement Cost =	$ 1,932,797.95	(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Annual Catalyst Replacement Cost = (Catalyst Replacement Cost) x (FWF)

Future Worth Factor = $FWF = i\left[\frac{1}{(1+i)^Y}\right]$

Interest rate, i =	9.00%	US Steel specific rate
$Term\ ,\ Y = \frac{h_{catalyst}}{h_{year}}$ =	3	
$h_{catalyst}$ =	24000	hours (operating life of catalyst as per pg. 2-47 of SCR manual)
h_{year} =	8760	hours = t_{op}
FWF =	0.34	
Annual Catalyst Replacement Cost =	$ 653,205	
Total DAC =	$ 9,384,353	

Indirect Annual Costs, IDAC:

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

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

Interest rate, i =	9.00%	US Steel specific rate
Economic life of SNCR, n=	20	years
CRF =	0.110	

TCI = Total Capital Investment = $ 13,224,639.95

IDAC = $ 1,448,713

Total Annual Cost:
Total Annual Cost, TAC = DAC + IDAC = $ 10,833,065.57

Total NO_X removed = 1438 tpy

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

Site Information

Utility Unit Costs	
Electricity, $/kwh	0.07
Interest Rate, %	9.00%
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%

Source Emission Information

Equipment Life, yr	20.0
Operating Hours Per Year	8760

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	760
NOX Removal Efficiency, η_{NOx}	80%
Cost Year	2014
Incremental Utility Requirement	
Electricity, kw	330
Reagent sol, gal/hr	58.8
Catalyst operating life, hrs	24000
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	19750
Reagent Cost, $/gallon	2.20

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

TOTAL CAPITAL INVESTMENT				TOTAL ANNUAL COST				COST EFFECTIVENESS	
Total Direct Capital Cost, DC	$ 9,364,301			**Direct Annual Costs**				NOX_{in}, lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger)	$ -			Operating & Supervisory Labor	$38,325			Efficiency, %	80%
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.				Maintenance	$198,370			Boiler Heat Input, MMBtu/hr	760
				Reagent Consumption	$1,132,790			Total Operating Time, hrs/yr	8760
				Utilities	$202,074				
				Catalyst Replacement	$653,205			NO_X removed, tpy	1,438.0
Total Indirect Capital Costs:				Auxiliary Equipment Requirements (Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)	$7,197,914				
Indirect Capital, IC	$ 1,872,860								
Project Contingency, C	$ 1,685,574								
Total Plant Cost, D (DC + IC + C)	$12,922,736								
				Total Direct Annual Costs			$9,422,678		
	$	-						**Cost Efficiency:**	
Royalty Allowance, F	$	-						**$/ton NO_X removed**	$ 7,560
Preproduction Costs, G	$	258,455		**Indirect Annual Costs**					
Inventory Capital, H	$	43,449		CRF	0.110				
Initial Catalyst and Chemicals, I	$	-		IDAC (CRF x TCI)			$1,448,713		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)			**$ 13,224,640**	**TOTAL ANNUAL COST, TAC**			**$10,871,391**		

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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.

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

$$CF_{Boiler2_1} = \frac{Actual2012, MMBtu/hr}{Potential MMBtu/hr}$$

$Actual_{2012}$	216	MMBtu/hr
Potential	481	MMBtu/hr
CFBoiler2=	0.45	

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

t_{SCR}	365	days/yr
CF_{SCR}=	1.00	
CF_{total}=	0.45	

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	80%	
Stack NO_X =	0.108	lb/MMBtu (Estimated)

Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent NH2 injected}}{\text{mole of uncontrolled } NO_X}$$

The value for ASR in a typical SCR system is approximately = 1.05

Normalized Stoichiometric Ratio, NSR

NSR = ASR X SR_1 (As per pg. 1-24 of SCR manual)

SR_1 = 1 (Ratio of equivalent moles of NH_3 per mole of reagent injected.)

NSR = 1.05

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Flue Gas Flow Rate, $q_{fluegas}$

$q_{fluegas}$ = 155,000 acfm - based on testing at boilers.

Space Velocity and Area Velocity, V_{space} & V_{area} Vanadium (V2O5)Catalyst on honeycomb substract with average pitch assumed

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

$Vol_{reactor}$ = 3100 ft^3

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

$Area_{reactor}$ = 775 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, $Vol_{catalyst}$ pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor}$ 3100

SCR Reactor Dimensions

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

$A_{catalyst}$ = 161.5 ft^2

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

A_{SCR} = 185.7 ft^2

l_{scr} = 13.6 ft

w_{scr} = 13.6 ft

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

h'_{layer} =	3.1	ft (nominal hegiht as per pg. 2-38 of SCR manual)
n_{layer} =	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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 pracitce)
c_2 =	9	
h_{SCR} =	88.8	

Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NOx_{in} \times Q_B \times NSR \times \eta_{NO_x} \times M_{reagent}}{M_{NO_x} \times SR_F}$$

NOx_{in} =	0.54	lb/MMBtu
Q_B =	48.3	MMBtu/hr
NSR =	1.05	
η_{NO_x} =	80%	
$M_{reagent}$ =	17.03	grams NH_3/mole
M_{NOx} =	46.01	grams NO_2/mole
SR_F =	3	(Ratio of equivalent moles of NH_3 per mole of reagent injected.)
$\dot{m}_{reagent}$ =	80.8	lbs/hr

For ammonia,

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

C_{sol} =	29%		(Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)
$\dot{m}_{sol}$ =	278.5	lbs/hr	

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

r_{sol} =	56	lb/ft^3	(For a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)
v_{sol} =	7.481	gal/ft^3	(Specific volume of a 20% solution ammonia at 60°F, pg. 2-40 of SCR manual)
q_{sol} =	37.2	gph	

Tank volume:

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

t	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol_{Tank} =	12500	gallons	

TOTAL CAPITAL INVESTMENT, TCI

Assumptions:

* High-dust SCR system
* 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.
* Costs for the tail-end arrangement cannot be estimated here because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements

Cost Year = 2014

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.

DC= Direct Capital costs includes PEC such as SCR 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, equations noted in 1998 dollars, TDC corrected below:

$$DC = Q_B\left[\frac{\$3{,}380}{MMBtu/hr} + f(h_{SCR}) - f(NH_3rate) + f(new) + f(bypass)\right]$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[\frac{\$6.12}{ft - MMBTu/hr}\, h_{SCR}\right] - \frac{\$187.9}{MMBtu/hr}$$

$f(h_{SCR})$ = 356

Adjustment for the ammonia flow rate:

$$f(NH_3rate) = \left[\frac{\$411}{lb/hr}\,\frac{m_{reagent}}{Q_B}\right] - \frac{\$47.3}{MMBtu/hr}$$

$f(NH_3rate)$ = $ 21.70

For a retrofit:

f(new) = $ - per MMBut/hr

For a new boiler:

f(new) = $ (728) per MMBut/hr

Adjustmnent for installing an SCR bypass:

f(bypass) = $ - per MMBut/hr (if no bypass installed)
f(bypass) = $ 327 per MMBut/hr (if bypass installed)

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst}CC_{initial}$$

$Vol_{catalyst}$ = $ 3,100.00 ft^3
$CC_{initial}$ = $ 240 per ft^3 (Cost of initial catalyst current estimation for a ceramic honeycomb catalyst)
$f(Vol_{catalyst})$ = 744000

Direct Capital, DC = $ 6,617,415 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs

Average values of indirect installation factors are applied to the direct capital cost estimate to obtain values for indirect installation costs. These costs are estimated as a percentage of the TCI.

Total Indirect Installation Costs, IC =	$	1,323,483	
=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 =		1191134.71	
=		15%	of DC + IC
Total Plant Cost, D =	$	9,132,032.78	= DC + IC + C
Allowance for Funds During Construction, E =	$	-	(Assumed zero for SCR)
Royalty Allowance,F =	$	-	(Assumed zero for SCR)
Preproduction Costs, G =	$	182,640.66	
=		2%	of D + E
Inventory Capital, H =	$	27,498.95	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ =		12500	gal/yr
$Cost_{reagent}$ =		2.2	$/gal (Mundi Index, Spot Market, January 2014)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SCR)
Total Capital Investment, TCI =	$	9,342,172.38	= D + E + F + G + H + I

TOTAL ANNUAL COSTS

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

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

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

Maintenance:

1.5% of TCI

Maintenance = $ 140,133

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

Reagent Consumption:

$cost_{reagent}$ 2.2 $/gallon

Annual reagent cost = $ 716,937 = $q_{reagent}$ x $cost_{reagent}$ x t_{op}

Utilities:

$$Power = 0.105 Q_g \left[NO_{in} \eta_{NO_x} + 0.5 \left(\Delta P_{duct} + n_{catalyst} \Delta P_{catalyst} \right) \right]$$

ΔP_{duct} = 2 inches water (Typical values as per pg. 2-46 of SCR manual)

$\Delta P_{catalyst}$ = 0.75 inches water (Typical values as per pg. 2-46 of SCR manual)

Power = 208.6

$Cost_{elec}$ = 0.07 $/kwh

t_{op} = 8760 hours

Annual electricity cost = P x $Cost_{elect}$ x t_{op} = $ 127,892

Additional Energy Requirement = $ 3,862,893 (Additional heating of exhaust gas required for SCR operations.)

Catalyst Replacement:

Catalyst Replacement Cost = n_{SCR} x $Vol_{catalyst}$ x ($CC_{replace}/R_{layer}$)

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)
Catalyst Replacement Cost =	$ 1,097,376.12	(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Annual Catalyst Replacement Cost = (Catalyst Replacement Cost) x (FWF)

Future Worth Factor = $FWF = i\left[\frac{1}{(1+i)}\right]$

Interest rate, i =	9.00%	US Steel specific rate
$Term\ ,Y = \frac{h_{catalyst}}{h_{year}}$ =	3	
$h_{catalyst}$ =	24000	hours (operating life of catalyst as per pg. 2-47 of SCR manual)
h_{year} =	8760	hours = t_{op}
FWF =	0.34	
Annual Catalyst Replacement Cost =	$ 370,867	
Total DAC =	$ 5,218,722	

Indirect Annual Costs, IDAC:

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

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

Interest rate, i =	9.00%	US Steel specific rate
Economic life of SNCR, n=	20	years
CRF =	0.11	
TCI = Total Capital Investment =	$ 9,342,172.38	
IDAC =	$ 1,023,402	

Total Annual Cost:
Total Annual Cost, TAC = DAC + IDAC = $ 6,242,123.68

Total NO_X removed = 910.1 tpy

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

Site Information

Utility Unit Costs	
Electricity, $/kwh	0.07
Interest Rate, %	9.00%
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%

Source Emission Information

Equipment Life, yr	20.0
Operating Hours Per Year	8760

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	481
NOX Removal Efficiency, η_{NOx}	80%
Cost Year	2014
Incremental Utility Requirement	
Electricity, kw	209
Reagent sol, gal/hr	37.2
Catalyst operating life, hrs	24000
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	12500
Reagent Cost, $/gallon	2.20

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

TOTAL CAPITAL INVESTMENT				TOTAL ANNUAL COST				COST EFFECTIVENESS		
Total Direct Capital Cost, DC	$ 6,617,415			**Direct Annual Costs**				NOX_m, lbs/MMBtu		0.54
Auxilliary Equipment (Heat Exchanger)	$ -			Operating & Supervisory Labor	$38,325			Efficiency, %		80%
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.				Maintenance	$140,133			Boiler Heat Input, MMBtu/hr		481
				Reagent Consumption	$716,937			Total Operating Time, hrs/yr		8760
				Utilities	$127,892					
				Catalyst Replacement	$370,867			NO_X removed, tpy		910.1
Total Indirect Capital Costs:				Auxilliary Equipment Requirements (Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)	$3,862,893					
Indirect Capital, IC	$ 1,323,483									
Project Contingency, C	$ 1,191,135									
Total Plant Cost, D (DC + IC + C)	$ 9,132,033									
Allowance for Funds During Constr., E	$ -			Total Direct Annual Costs			$5,257,047	**Cost Efficiency:**		
Royalty Allowance,F	$ -							**$/ton NO_X removed**	$	6,901
Preproduction Costs, G	$ 182,641			**Indirect Annual Costs**						
Inventory Capital, H	$ 27,499			CRF	0.110					
Initial Catalyst and Chemicals, I	$ -			IDAC (CRF x TCI)			$1,023,402			
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)		$	9,342,172	**TOTAL ANNUAL COST, TAC**			**$6,280,449**			

United States Steel - Clairton
RACT Analysis Boiler R1/R2
NOx Controls Cost Effectiveness Evaluation
SCR Technology
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

SCR Design Parameters used for Estimation

Boiler # R1/R2 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

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

$$CF_{R1R2} = \frac{Actual\,2012, MMBtu/hr}{Potential, MMBtu/hr}$$

	$Actual_{2012}$	13.44	MMBtu/hr
	Potential	229	MMBtu/hr
$CF_{R1\,R21}$=	0.06		

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

	t_{SCR}	365	days/yr
CF_{SCR}=	1.00		
CF_{total}=	0.06		

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	80%	
Stack NO_X =	0.108	lb/MMBtu (Estimated)

Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent NH2 injected}}{\text{mole of uncontrolled } NO_X}$$

The value for ASR in a typical SCR system is approximately = 1.05

Normalized Stoichiometric Ratio, NSR

NSR = ASR X SR_1 (As per pg. 1-24 of SCR manual)

SR_1 = 1 (Ratio of equivalent moles of NH_3 per mole of reagent injected.)

NSR = 1.05

United States Steel - Clairton
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Flue Gas Flow Rate, $q_{fluegas}$

$q_{fluegas}$ = 62,800 acfm - based on testing at boilers

Space Velocity and Area Velocity, V_{space} & V_{area} Vanadium (V2O5)Catalyst on honeycomb substract with average pitch assumed

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

$Vol_{reactor}$ = 1256 ft^3

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

$Area_{reactor}$ = 314 ft^2

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

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

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

Catalyst Volume, $Vol_{catalyst}$ pg 2-36 of SCR manual

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

$Vol_{catalyst}$ = $Vol_{reactor}$ 1256

SCR Reactor Dimensions

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

$A_{catalyst}$ = 65.4 ft^2

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

A_{SCR} = 75.2 ft^2

l_{scr} = 8.7 ft

w_{scr} = 8.7 ft

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

h'_{layer} =	3.1	ft (nominal hegiht as per pg. 2-38 of SCR manual)
n_{layer} =	6.2	(There must be at least two catalyst layers, pg. 2-38 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} =	7.193548387	(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 pracitce)
c_2 =	9	
h_{SCR} =	88.8483871	

Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NOx_{in} \times Q_B \times NSR \times \eta_{NOx} \times M_{reagent}}{M_{NOx} \times SR_T}$$

NOx_{in} =	0.54	lb/MMBtu
Q_B =	229	MMBtu/hr
NSR =	1.05	
η_{NOx} =	80%	
$M_{reagent}$ =	17.03	grams NH_3/mole
M_{NOx} =	46.01	grams NO_2/mole
SR_T =	1	(Ratio of equivalent moles of NH_3 per mole of reagent injected.)
$\dot{m}_{reagent}$ =	38.4	lbs/hr

For ammonia,

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

C_{sol} =	29%		(Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)
$\dot{m}_{sol}$ =	132.6	lbs/hr	

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

r_{sol} =	56	lb/ft^3	(For a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)
v_{sol} =	7.481	gal/ft^3	(Specific volume of a 20% solution ammonia at 60°F, pg. 2-40 of SCR manual)
q_{sol} =	17.7	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol_{Tank} =	5951	gallons	

TOTAL CAPITAL INVESTMENT, TCI

Assumptions:

* High-dust SCR system
* 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.
* Costs for the tail-end arrangement cannot be estimated here because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements.

Cost Year = 2014

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.

DC= Direct Capital costs includes PEC such as SCR 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, equations noted in 1998 dollars, TDC corrected below:

$$DC = Q_B\left[\frac{\$3{,}380}{MMBtu/hr} + f_{h_{SCR}} + f_{(NH_3 rate)} + f_{(new)} + f_{(bypass)}\right]\left(\frac{3500}{Q_B}\right)^{0.35} + f(Vol_{(catalyst)})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[\frac{\$6.12}{ft - MMBTu/hr} h_{SCR}\right] - \frac{\$187.9}{MMBtu/hr}$$

$f(h_{SCR})$ = 356

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[\frac{\$411}{lb/hr}\frac{m_{reagent}}{Q_B}\right] - \frac{\$47.3}{MMBtu/hr}$$

$f(NH_3 rate)$ = $ 21.70

For a retrofit:

f(new) = $ - per MMBut/hr

For a new boiler:

f(new) = $ (728) per MMBut/hr

Adjustmnent for installing an SCR bypass:

f(bypass) = $ - per MMBut/hr (if no bypass installed)
f(bypass) = $ 127 per MMBut/hr (if bypass installed)

Capital cost for initial catalyst charge

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$Vol_{catalyst}$ = $ 1,256.00 ft^3
$CC_{initial}$ = $ 240 per ft^3 (Cost of initial catalyst:current estimation for a ceramic honeycomb catalyst)
$f(Vol_{catalyst})$ = 301440

Direct Capital, DC = $ 3,852,154 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs

Average values of indirect installation factors are applied to the direct capital cost estimate to obtain values for indirect installation costs. These costs are estimated as a percentage of the TCI.

Total Indirect Installation Costs, IC =	$	770,431	
=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 =	$	693,388	
=		15%	of DC + IC
Total Plant Cost, D =	$	5,315,972.34	= DC + IC + C
Allowance for Funds During Construction, E =	$	-	(Assumed zero for SCR)
Royalty Allowance, F =	$	-	(Assumed zero for SCR)
Preproduction Costs, G =	$	106,319.45	
=		2%	of D + E
Inventory Capital, H =	$	13,092.02	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ =		5951	gal/yr
$Cost_{reagent}$ =		2.2	$/gal (Mundi Index, Spot Market, January 2014)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SCR)
Total Capital Investment, TCI =	$	5,435,383.81	= D + E + F + G + H + I

TOTAL ANNUAL COSTS

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

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

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

Maintenance:

1.5%	of TCI		
Maintenance =	$	81,531	
Total operating time, t_{op} = CF_{total} x 8760 hrs/yr		8760	hours (CF not used as max hours required for RACT analysis)

Reagent Consumption:

$cost_{reagent}$		2.2	$/gallon
Annual reagent cost =	$	341,328	= $q_{reagent}$ x $cost_{reagent}$ x t_{op}

Utilities:

$$Power = 0.105 Q_g \left[NOx _ \eta_{NOx} + 0.5 \left(\Delta P_{duct} + n_{total} \Delta P_{catalyst} \right) \right]$$

DP_{duct} =		2	inches water (Typical values as per pg. 2-46 of SCR manual)
$DP_{catalyst}$ =		0.75	inches water (Typical values as per pg. 2-46 of SCR manual)
Power =		99.3	
$Cost_{elec}$ =		0.07	$/kwh
t_{op} =		8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	$	60,888	
Additional Energy Requirement =	$	1,328,846	(Additional heating of exhaust gas required for SCR operations.)

Catalyst Replacement:

Catalyst Replacement Cost = n_{SCR} x $Vol_{catalyst}$ x ($CC_{replace}/R_{layer}$)

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)
Catalyst Replacement Cost =	$ 444,614.33	(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Annual Catalyst Replacement Cost = (Catalyst Replacement Cost) x (FWF)

Future Worth Factor = $FWF = i\left[\frac{1}{(1+i)}\right]$

Interest rate, i =	9.00%	US Steel Specific interest rate
$Term\ , Y = \frac{h_{catalyst}}{h_{year}}$ =	3	
$h_{catalyst}$ =	24000	hours (operating life of catalyst as per pg. 2-47 of SCR manual)
h_{year} =	8760	hours = t_{op}
FWF =	0.34	
Annual Catalyst Replacement Cost =	$ 150,261	
Total DAC =	$ 1,962,853	

Indirect Annual Costs, IDAC:

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

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

Interest rate,i =	9.00%	US Steel Specific interest rate
Economic life of SNCR, n=	20	years
CRF =	0.11	
TCI = Total Capital Investment =	$ 5,435,383.81	
IDAC =	$ 595,427	

Total Annual Cost:
Total Annual Cost, TAC = DAC + IDAC = $ 2,558,280.33

Total NO_X removed = 433 tpy

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s R1/R2
NOX Emission Control Option: SCR (80% Efficiency)

Site Information

Utility Unit Costs	
Electricity, $/kwh	0.07
Interest Rate, %	9.00%
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%

Source Emission Information

Equipment Life, yr	20.0
Operating Hours Per Year	8760

Control Technology Information

Heater Fuel Rating, mmBTU/hr	229
NOX Removal Efficiency, η_{NOx}	80%
Cost Year	2014
Incremental Utility Requirement	
Electricity, kw	99
Reagent sol, gal/hr	17.7
Catalyst operating life, hrs	24000
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	5951
Reagent Cost, $/gallon	2.20

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s R1/R2
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			TOTAL ANNUAL COST			COST EFFECTIVENESS	
Total Direct Capital Cost, DC	$ 3,852,154		**Direct Annual Costs**			NOX_{in}, lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger)	$ -		Operating & Supervisory Labor	$38,325		Efficiency, %	80%
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.			Maintenance	$81,531		Boiler Heat Input, MMBtu/hr	229
			Reagent Consumption	$341,328		Total Operating Time, hrs/yr	8760
			Utilities	$60,888			
			Catalyst Replacement	$150,261		NO_X removed, tpy	433.3
Total Indirect Capital Costs:			Auxilliary Equipment Requirements (Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)	$1,328,846			
Indirect Capital, IC	$ 770,431						
Project Contingency, C	$ 693,388						
Total Plant Cost, D (DC + IC + C)	$ 5,315,972		Total Direct Annual Costs		$2,001,178		
Allowance for Funds During Constr., E	$ -					**Cost Efficiency:**	
Royalty Allowance, F	$ -					**$/ton NO_X removed**	**$ 5,993**
Preproduction Costs, G	$ 106,319		**Indirect Annual Costs**				
Inventory Capital, H	$ 13,092		CRF	0.110			
Initial Catalyst and Chemicals, I	$ -		IDAC (CRF x TCI)		$595,427		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$ 5,435,384**		**TOTAL ANNUAL COST, TAC**		**$2,596,605**		

SCR Design Parameters used for Estimation

Boiler T1/T2 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.

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

$$CF_{T1T2} = \frac{Actual2012, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012}$	18.56	MMBtu/hr
Potential	156	MMBtu/hr
$CFT1/T2_1$ =	0.12	

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

t_{SCR}	365	days/yr
CF_{SCR} =	1.00	
CF_{total} =	0.12	

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled) =	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	80%	
Stack NO_X =	0.108	lb/MMBtu (Estimated)

Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_3 \text{ injected}}{\text{mole of uncontrolled } NO_X}$$

The value for ASR in a typical SCR system is approximately = 1.05

Normalized Stoichiometric Ratio, NSR

NSR = ASR X SR_1 (As per pg. 1-24 of SCR manual)

SR_1 = 1, (Ratio of equivalent moles of NH_3 per mole of reagent injected.)

NSR = 1.05

United Sates Steel - Clairton
RACT Analysis Boiler 11/12
NOx Controls Cost Effectiveness Evaluation
SCR Technology
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

Flue Gas Flow Rate, $q_{flueg as}$

$q_{flueg as}$ = 46,600 acfm - based on testing of boilers

Space Velocity and Area Velocity, V_{space} & V_{area} Vanadium (V2O5)Catalyst on honeycomb substract with average pitch assumed

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

$Vol_{reactor}$ = 932 ft^3

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

$Area_{reactor}$ = 233 ft^2

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

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

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

Catalyst Volume, $Vol_{catalyst}$ pg 2-36 of SCR manual

$$Vol_{catalyst} = \frac{-\left(q_{flueg as} \times \ln\left[1-\left(\frac{\eta_{NOx}}{ASR}\right)\right]\right)}{K_{catalyst} \times A_{specific}}$$

$Vol_{catalyst} = Vol_{reactor}$ 932

SCR Reactor Dimensions

$$A_{catalyst} = \frac{q_{flueg as}}{16.\ ft/s \times 60\ sec/min}$$

$A_{catalyst}$ = 48.5 ft^2

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

A_{SCR} = 55.8 ft^2

l_{scr} = 7.5 ft

w_{scr} = 7.5 ft

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

h'_{layer} =	3.1	ft (nominal hegiht as per pg. 2-38 of SCR manual)
n_{layer} =	6.2	(There must be at least two catalyst layers, pg. 2-38 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

$$\dot{m}_{reagent} = \frac{NOx_{in} \times Q_H \times NSR \times \eta_{NO_x} \times M_{reagent}}{M_{NO_x} \times SR_T}$$

NOx_{in} =	0.54	lb/MMBtu
Q_H =	156	MMBtu/hr
NSR =	1.05	
η_{NO_x} =	80%	
$M_{reagent}$ =	17.03	grams NH_3/mole
M_{NO_x} =	46.01	grams NO_2/mole
SR_T =	1	(Ratio of equivalent moles of NH_3 per mole of reagent injected.)
$\dot{m}_{reagent}$ =	26.2	lbs/hr

For ammonia,

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

C_{sol} =	29%		(Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)
$\dot{m}_{sol}$ =	90.3	lbs/hr	

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

ρ_{sol} =	56	lb/ft^3	(For a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)
v_{sol} =	7.481	gal/ft^3	(Specific volume of a 20% solution ammonia at 60°F, pg. 2-40 of SCR manual)
q_{sol} =	12.1	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol_{Tank} =	4054	gallons	

TOTAL CAPITAL INVESTMENT, TCI

Assumptions:

* High-dust SCR system
* 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.
* Costs for the tail-end arrangement cannot be estimated here because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements

Cost Year = 2014

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.

DC= Direct Capital costs includes PEC such as SCR 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, equations noted in 1998 dollars, TDC corrected below:

$$DC = Q_B\left[\frac{\$3{,}380}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass)\right]$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[\frac{\$6.12}{ft - MMBtu/hr}\, h_{SCR}\right] - \frac{\$187.9}{MMBtu/hr}$$

$f(h_{SCR})$ = 356

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[\frac{\$411}{lb/hr}\,\frac{m_{reagent}}{Q_B}\right] - \frac{\$47.3}{MMBtu/hr}$$

$f(NH_3 rate)$ = $ 21.70

For a retrofit:

f(new) = $ - per MMBut/hr

For a new boiler:

f(new) = $ (728) per MMBut/hr

Adjustment for installing an SCR bypass:

f(bypass) = $ - per MMBut/hr (if no bypass installed)
f(bypass) = $ 127 per MMBut/hr (if bypass installed)

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst}\, CC_{initial}$$

$Vol_{catalyst}$ = $ 932.00 ft^3
$CC_{initial}$ = $ 240 per ft^3 (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)
$f(Vol_{catalyst})$ = 223680

Direct Capital, DC = $ 2,985,008 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs

Average values of indirect installation factors are applied to the direct capital cost estimate to obtain values for indirect installation costs. These costs are estimated as a percentage of the TCI.

Total Indirect Installation Costs, IC =	$ 597,002	
=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 =	$537,301	
=	15%	of DC + IC
Total Plant Cost, D =	$ 4,119,311.42	= DC + IC + C
Allowance for Funds During Construction, E =	$ -	(Assumed zero for SCR)
Royalty Allowance,F =	$ -	(Assumed zero for SCR)
Preproduction Costs, G =	$ 82,386.23	
=	2%	of D + E
Inventory Capital, H =	$ 8,918.58	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ =	4054	gal/yr
$Cost_{reagent}$ =	2.2	$/gal (Mundi Index, Spot Market, January 2014)
Initial Catalyst and Chemicals, I =	$ -	(Assumed zero for SCR)
Total Capital Investment, TCI =	$ 4,210,616.22	= D + E + F + G + H + I

TOTAL ANNUAL COSTS

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

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

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

Maintenance:

1.5%	of TCI		
Maintenance =	$	63,159	
Total operating time, t_{op} = CF_{total} x 8760 hrs/yr		8760	hours (CF not used as max hours required for RACT analysis)

Reagent Consumption:

$cost_{reagent}$		2.2	$/gallon
Annual reagent cost =	$	232,520	= $q_{reagent}$ x $cost_{reagent}$ x t_{op}

Utilities:

$$Power = 0.105 Q_g \left[NO_{in} \eta_{NO_x} + 0.5 \left(\Delta P_{duct} + n_{total} \Delta P_{catalyst} \right) \right]$$

DP_{duct} =		2	inches water (Typical values as per pg. 2-46 of SCR manual)
$DP_{catalyst}$ =		0.75	inches water (Typical values as per pg. 2-46 of SCR manual)
Power =		67.6	
$Cost_{elec}$ =		0.07	$/kwh
t_{op} =		8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	$	41,478	
Additional Energy Requirement =	$	1,020,364	(Additional heating of exhaust gas required for SCR operations.)

Catalyst Replacement:

Catalyst Replacement Cost = n_{SCR} x $Vol_{catalyst}$ x ($CC_{replace}/R_{layer}$)

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)	
Catalyst Replacement Cost =	$ 329,920.82	(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574	

Annual Catalyst Replacement Cost = (Catalyst Replacement Cost) x (FWF)

Future Worth Factor = $FWF = i\left[\frac{1}{(1+i)}\right]$

Interest rate, i =	9.00%	US Steel specific rate
$Term\ , Y = \frac{h_{catalyst}}{h_{year}}$ =	3	
$h_{catalyst}$ =	24000	hours (operating life of catalyst as per pg. 2-47 of SCR manual)
h_{year} =	8760	hours = t_{op}
FWF =	0.34	
Annual Catalyst Replacement Cost =	$ 111,499	
Total DAC =	$ 1,469,021	

Indirect Annual Costs, IDAC:

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

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

Interest rate, i =	9.00%	US Steel specific rate
Economic life of SNCR, n=	20	years
CRF =	0.11	

TCI = Total Capital Investment = $ 4,210,616.22

IDAC = $ 461,258

Total Annual Cost:
Total Annual Cost, TAC = DAC + IDAC = $ 1,930,278.97

Total NO_X removed = 295 tpy

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s T1/T2
NOX Emission Control Option: SCR (80% Efficiency)

Site Information

Utility Unit Costs	
Electricity, $/kwh	0.07
Interest Rate, %	9.00%
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%

Source Emission Information

Equipment Life, yr	20.0
Operating Hours Per Year	8760

Control Technology Information

Furance Fuel Rating, mmBTU/hr	156
NOX Removal Efficiency, η_{NOx}	80%
Cost Year	2014
Incremental Utility Requirement	
Electricity, kw	68
Reagent sol, gal/hr	12.1
Catalyst operating life, hrs	24000
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	4054
Reagent Cost, $/gallon	2.20

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s T1/T2
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT				TOTAL ANNUAL COST				COST EFFECTIVENESS		
Total Direct Capital Cost, DC	$ 2,985,008			**Direct Annual Costs**				NOX_{in}, lbs/MMBtu		0.54
Auxilliary Equipment (Heat Exchanger)	$ -			Operating & Supervisory Labor	$38,325			Efficiency, %		80%
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.				Maintenance	$63,159			Boiler Heat Input, MMBtu/hr		156
				Reagent Consumption	$232,520			Total Operating Time, hrs/yr		8760
				Utilities	$41,478					
				Catalyst Replacement	$111,499			NO_X removed, tpy		295
Total Indirect Capital Costs:				Auxilliary Equipment Requirements (Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)	$1,020,364					
Indirect Capital, IC	$ 597,002									
Project Contingency, C	$ 537,301									
Total Plant Cost, D (DC + IC + C)	$ 4,119,311									
Allowance for Funds During Constr., E	$ -			Total Direct Annual Costs			$1,507,346	**Cost Efficiency:**		
Royalty Allowance,F	$ -							**$/ton NO_X removed**	**$**	**6,669**
Preproduction Costs, G	$ 82,386			**Indirect Annual Costs**						
Inventory Capital, H	$ 8,919			CRF	0.110					
Initial Catalyst and Chemicals, I	$ -			IDAC (CRF x TCI)			$461,258			
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)		**$**	**4,210,616**	**TOTAL ANNUAL COST, TAC**			**$1,968,604**			

United State Steel
RACT Analysis for NOx - Clairton
Best Case NOX Removal with SNCR, Flue Gas Heating Cost Only

lbs NOX/MMcf Natural Gas: 140

Heat Capacity Boiler Combustion Stack Gas

	BOILER #1		BOILER #2		BOILER # R1/R2		BOILER # T1/T2	
	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)
H20	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
CO2	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
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	BOILER #1		BOILER #2		BOILER # R1/R2		BOILER # T1/T2	
Flow (1)	182,000	scfm	107,000	scfm	33,600	scfm	25,800	scfm
Flow	**1.09E+07**	**scfh**	**6.06E+06**	**scfh**	**2.02E+06**	**scfh**	**1.55E+06**	**scfh**
Temperature$_{SNCR\ in}$ (1)	**316**	**F**	**327**	**F**	**316**	**F**	**316**	**F**
Temperature$_{SNCR\ out}$ (2)	**1650**	**F**	**1650**	**F**	**1650**	**F**	**1650**	**F**
ΔT	**1334**	F	**1323**	F	**1334**	F	**1334**	F
Heat Requirement	25.5	Btu/scf	25.3	Btu/scf	25.5	Btu/scf	25.5	Btu/scf
Uncontrolled NOX (1), (3)	12718.6	ppmv	8049.5	ppmv	3832.3	ppmv	2610.7	ppmv
Uncontrolled NOX (3)	410.40	Lb / Hr	259.74	Lb / Hr	123.66	Lb / Hr	84.24	Lb / Hr
NOX control eff'y (2)	45%		45%		45%		45%	
NOX Removed	184.7	Lb / Hr	116.9	Lb / Hr	55.6	Lb / Hr	37.9	Lb / Hr
NOX Removed	1.69E-05	Lb / scf flue gas	1.93E-05	Lb / scf flue gas.	2.76E-05	Lb / scf flue gas	2.45E-05	Lb / scf flue gas
NOX from Natural Gas Combustion (4)	4.46E-06	Lb / scf flue gas	4.42E-06	Lb / scf flue gas	0.00E+00	Lb / scf flue gas	0.00E+00	Lb / scf flue gas
Net NOX Reduction	1.25E-05	Lb / scf flue gas.	1.49E-05	Lb / scf flue gas	2.76E-05	Lb / scf flue gas	2.45E-05	Lb / scf flue gas
Natural Gas Eff'y	80.0%		80.0%		80.0%		80.0%	
Natural Gas Req'd	31.8	Btu / scf flue gas	31.6	Btu / scf flue gas	31.8	Btu / scf flue gas	31.8	Btu / scf flue gas
Natural Gas Req'd	3.18E-05	MMBtu/scf flue gas	3.16E-05	MMBtu/scf flue gas	3.18E-05	MMBtu/scf flue gas	3.18E-05	MMBtu/scf flue gas
Natural Gas Cost (5)	$9.44	/ MMbtu	$9.44	/ MMbtu	$9.44	/ MMbtu	$9.44	/ MMbtu
Natural Gas Cost	$24.13	/ Lb NOX Removed	$20.05	/ Lb NOX Removed	$10.89	/ Lb NOX Removed	$12.27	/ Lb NOX Removed
Natural Gas Cost	**$48,258**	**/ Ton NOX Removed**	**$40,095**	**/ Ton NOX Removed**	**$21,775**	**/ Ton NOX Removed**	**$24,545**	**/ Ton NOX Removed**
Annual Natural Gas Cost (6)	$28,748,554		$15,822,314		$5,307,425		$4,075,344	

User inputs used in calculations

(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 or potential-to-emit values in tpy based on 8760 hrs/yr.
(4) Based on 140 lb NOX per MMscf natural gas
(5) Average utility gas rate, 2013, from US Bureau of Labor Statistics (www.bls.gov) for Pennsylvania Industrial Consumers
(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, $CF_{total} = CF_{plant} \times CF_{SNCR}$

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

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

$$CF_{Boiler\ \#1_1} = \frac{Actual_{2012}, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012}$	467.5	MMBtu/hr
Potential	760	MMBtu/hr
$CFboiler_1$=	0.62	

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

t_{SNCR}	365	days/yr
CF_{SNCR}=	1.00	
CF_{total}=	0.62	

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	45%	
Stack NO_X =	0.297	lb/MMBtu (Estimated)

Normalized Stoichiometric Ratio, NSR

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

NSR = 1.48

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 1-27 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) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_f}$$

$\dot{m}_{reagent}$ = 178.8 lbs/hr

Aqueous reagent solution mass flow rate

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

$\dot{m}_{sol}$ = 357.6 lbs/hr

Solution volume flow rate:

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

q_{sol} = 37.68 gph

Aqueous reagent solution storage:

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

$t_{storage}$ = 14.00 days (Assumption from pg. 1-27 in SNCR manual)

V_{tank} = 12659.11 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 2014

Includes: direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include the equipment cost (EC) for the SNCR 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.

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, instlation and painting. In addition costs such as asbestos removal are included.

PEC= Purchased Equipment Cost

IC= Indirect Capital

Total Direct Capital Costs, DC:

$$DC = \frac{\$950}{\frac{MMBtu}{hr}} Q_B\left(\frac{MMBtu}{hr}\right)\left\{\frac{2375\ \frac{MMBtu}{hr}}{Q_B\left(\frac{MMBtu}{hr}\right)}\right\}^{0.577}\left(0.66 + 0.85\eta_{NO}\right)$$

DC = $ 2,142,517.09 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs:

Total Indirect Installation Costs, IC = $ 428,503

=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 = $ 385,653.08

= 15% of DC + IC

Total Plant Cost, D = $ 2,956,673.58 = DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)
Royalty Allowance,F =	$	-	(Assumed zero for SNCR)
Preproduction Costs, G =	$	59,133.47	
=		2%	of D + E
Inventory Capital, H =	$	608,903.33	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ =		329137	gal/yr
$Cost_{reagent}$ =		1.85	$/gal $/gallon (Mundi Price Index for January 2014, United States)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SNCR)
Total Capital Investment, TCI =	$	3,624,710.39	= 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 SNCR.
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.

Maintenance:

		1.5%	of TCI
Maintenance =	$	54,371	

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

Reagent Consumption (Urea):

$cost_{reagent}$		1.85	$/gallon (Mundi Price Index for January 2014, United States)
Annual reagent cost =	$	610,576	= 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)=	0.54	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):	1.483333333	
Q_B, boiler heat input=	760	MMBtu/hr
P =	30	kw
$Cost_{elec}$ =	0.07	$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)
t_{op} =	8760	hours

Annual electricity cost = P x $Cost_{elect}$ x t_{op} = $ 18,468 per kWh

Water Consumption:

$$q_{water} = \frac{m_{sol}}{\rho_{water}} \left(\frac{C_{urea\,Sol_{orig}}}{C_{urea\,Sol_{dil}}} - 1 \right)$$

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

$$q_{water} = \frac{4 m_{sol}}{\rho_{water}}$$

ρ_{water} =	8.345	lb/gal
q_{water} =	0.17141	1,000 gallons/hour

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

$Cost_{water}$ =		8.37	$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial User
	$	12,567.67	http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.shtml

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 1.4483$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Coke oven gas	409.5	MMBtu/hr
Natural gas	58.00	MMBtu/hr
Total MMBtu/hr	467.50	

Percent usage:

Coke oven gas	0.88
Natural gas	0.12

Additional fuel required:

Natural gas	1.44826	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost		9.44	$/MMBtu
	$	119,763.05	$/yr
Total Natural gas:	$	119,763.05	
Additional Energy Requirement =	$	28,748,554	(Additional heating of exhaust gas required for SNCR operations.)
Total DAC =	$	29,564,299.75	

Indirect Annual Costs:

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

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

Interest rate, i =	9.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n=	20	years
CRF =	0.11	

TCI = Total Capital Investment = $ 3,624,710.39

IDAC = $ 397,074.25

Total Annual Cost:
Total Annual Cost, TAC = DAC + IDAC = $ 29,961,373.99

Total NO_X removed = 809 tpy

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

Site Information

Utility Unit Costs

Electricity, $/kwh	0.07
Interest Rate, %	9.00%
Water, $/1,000 gal	8.37
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	760
NOX Removal Efficiency, η_{NOx}	45%
Cost Year	2014

Incremental Utility Requirements

Electricity, kw	30
Reagent sol, gal/hr	37.38
Water, 1,000 gal/hr	0.47
NG, MMBtu/hr	1.44826

Reagent Volume, gallons	329137
Reagent Cost, $/gallon	1.85

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		$	2,142,517								
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 Installation, IC		$	428,503								
Project Contingency, C		$	385,653								
Total Plant Cost, D (DC + IC + C)		$	2,956,674								
Allowance for Funds During Constr., E		$	-								
Royalty Allowance,F		$	-								
Preproduction Costs, G		$	59,133								
Inventory Capital, H		$	608,903								
Initial Catalyst and Chemicals, I		$	-								
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)		**$**	**3,624,710**								

TOTAL ANNUAL COST			
Direct Annual Costs			
Operating & Supervisory Labor	$38,325		
Maintenance	$54,371		
Reagent Consumption	$610,576		
Utilities	$18,468		
Water Consumption	$12,568		
Add'l Fuel Usage (Process related)	$119,763.05		
Auxilliary Equipment Requirements	$28,748,554		
(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Direct Annual Costs			$29,602,625
Indirect Annual Costs			
CRF	0.110		
Total IDAC (CRF x TCI)		$	397,074
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$**	**29,999,699**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.54
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	760
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	808.9
Cost Efficiency:	
$/ton NO_X removed	**$37,087**

SNCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input, Q_B = 481 MMBtu/hr

System Capacity Factor, $CF_{total} = CF_{plant} \times CF_{SNCR}$

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

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

$$CF_{Boiler\#2_1} = \frac{Actual_{2012}, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012}$	216	MMBtu/hr
Potential	481	MMBtu/hr
CFBoiler2=	0.45	

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

t_{SNCR}	365	days/yr
CF_{SNCR}=	1.00	
CF_{total}=	0.45	

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	45%	
Stack NO_X =	0.297	lb/MMBtu (Estimated)

Normalized Stoichiometric Ratio, NSR

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

NSR = 1.48

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 1-27 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) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$\dot{m}_{reagent}$ = 113.2 lbs/hr

Aqueous reagent solution mass flow rate:

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

m_{sol} = 226.3 lbs/hr

Solution volume flow rate:

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

q_{sol} = 23.84 gph

Aqueous reagent solution storage:

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

$t_{storage}$ = 14.00 days (Assumption from pg. 1-27 in SNCR manual)

V_{tank} = 8011.89 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 2014

Includes: direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include the equipment cost (EC) for the SNCR 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.

United States Steel - Clairton
RACT Analysis for NOx - Boiler #2
NOx Controls Cost Effectivness Evaluation
SNCR Technology
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

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 = $ 1,765,580.45 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs:

Total Indirect Installation Costs, IC = $ 353,116

=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 = $ 317,804.48

= 15% of DC + IC

Total Plant Cost, D = $ 2,436,501.03 = DC + IC + C

Allowance for Funds During Construction, E = $ - (Assumed zero for SNCR)

Royalty Allowance,F = $ - (Assumed zero for SNCR)

Preproduction Costs, G = $ 48,730.02
= 2% of D + E

Inventory Capital, H = $ 385,371.71 = $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ = 208309 gal/yr
$Cost_{reagent}$ = 1.85 $/gal $/gallon (Mundi Price Index for January 2014, United States)

Initial Catalyst and Chemicals, I = $ - (Assumed zero for SNCR)

Total Capital Investment, TCI = $ 2,870,602.76 = 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 SNCR.
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.

Maintenance:
1.5% of TCI
Maintenance = $ 43,059

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

United States Steel - Clairton
RACT Analysis for NOx - Boiler #2
NOx Controls Cost Effectivness Evaluation
SNCR Technology
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

Reagent Consumption (Urea):

$cost_{reagent}$		1.85	$/gallon (Mundi Price Index for January 2014, United States)
Annual reagent cost =	$	386,430	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):	1.483333333	
Q_B, boiler heat input=	481	MMBtu/hr
P =	19	kw
$Cost_{elec}$ =	0.07	$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)
t_{op} =	8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} = $	11,688	per kWh

Water Consumption:

$$q_{water} = \frac{m_{sol}}{\rho_{water}} \left(\frac{C_{UreaSol_{used}}}{C_{UreaSol_{in}}} - 1 \right)$$

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

$$q_{water} = \frac{4 m_{sol}}{\rho_{water}}$$

ρ_{water} =	8.345	lb/gal
q_{water} =	0.10848	1,000 gallons/hour

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

$Cost_{water}$ =		8.37	$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial User
	$	7,954.02	http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.html

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.9166$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Coke oven gas	189.6	MMBtu/hr
Natural gas	26.40	MMBtu/hr
Total MMBtu/hr	216.00	

Percent usage:

Coke oven gas	0.88
Natural gas	0.12

Additional fuel required:

Natural gas	0.91660	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost		9.44	$/MMBtu
	$	75,797.40	$/yr
Total Natural gas:	$	75,797.40	
Additional Energy Requirement =	$	15,822,314	(Additional heating of exhaust gas required for SNCR operations.)
Total DAC =	$	16,347,243.57	

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 =		9.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n=		20	years
CRF =		0.11	
TCI = Total Capital Investment =	$	2,870,602.76	
IDAC =	$	314,464.41	

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC =	$	16,661,707.98	
Total NO_X removed =		511.9	tpy

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

Site Information

Utility Unit Costs

Electricity, $/kwh	0.07
Interest Rate, %	9.00%
Water, $/1,000 gal	8.37
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	481
NOX Removal Efficiency, η_{NOx}	45%
Cost Year	2014

Incremental Utility Requirements

Electricity, kw	19
Reagent sol, gal/hr	23.84
Water, 1,000 gal/hr	0.11
NG, MMBtu/hr	0.91660

Reagent Volume, gallons	208309
Reagent Cost, $/gallon	1.85

1

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

TOTAL CAPITAL INVESTMENT				TOTAL ANNUAL COST				COST EFFECTIVENESS	
Total Direct Capital Cost, DC	$	1,765,580		**Direct Annual Costs**				NOX_{in}, lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger)	$	-		Operating & Supervisory Labor	$38,325			Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.				Maintenance	$43,059			Boiler Heat Input, MMBtu/hr	481
				Reagent Consumption	$386,430			Total Operating Time, hrs/yr	8760
				Utilities	$11,688				
				Water Consumption	$7,954			NO_X removed, tpy	511.9
Total Indirect Capital Costs:				Add'l Fuel Usage (Process related)	$75,797.40				
Indirect Capital, IC	$	353,116		Auxilliary Equipment Requirements	$15,822,314				
Project Contingency, C	$	317,804		(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)					
Total Plant Cost, D (DC + IC + C)	$	2,436,501							
				Total Direct Annual Costs			$16,385,569	**Cost Efficiency:**	
Allowance for Funds During Constr., E	$	-						**$/ton NO_X removed**	**$32,621**
Royalty Allowance,F	$	-							
Preproduction Costs, G	$	48,730		**Indirect Annual Costs**					
Inventory Capital, H	$	385,372		CRF	0.110				
Initial Catalyst and Chemicals, I	$	-		Total IDAC (CRF x TCI)		$	314,464		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**2,870,603**		**TOTAL ANNUAL COST, TAC (DAC + IDAC)**		**$**	**16,700,033**		

SNCR Design Parameters used for Estimation

Boiler # **R1/R2 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 furnace in conjunction with the SNCR system.

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

$$CF_{R1R2} = \frac{Actual_{2012}, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012}$	13.44	MMBtu/hr
Potential	229	MMBtu/hr
CF_{R1R2}=	0.06	

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

t_{SNCR}	365	days/yr
CF_{SNCR}=	1.00	
CF_{total}=	0.06	

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NO_X}	45%	
Stack NO_X =	0.297	lb/MMBtu (Estimated)

Normalized Stoichiometric Ratio, NSR

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

NSR = 1.48

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 1-27 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) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$\dot{m}_{reagent}$ = 53.9 lbs/hr

Aqueous reagent solution mass flow rate:

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

$\dot{m}_{sol}$ = 107.7 lbs/hr

Solution volume flow rate:

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

q_{sol} = 11.35 gph

Aqueous reagent solution storage:

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

$t_{storage}$ = 14.00 days (Assumption from pg. 1-27 in SNCR manual)

V_{tank} = 3814.39 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 2014

Includes: direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include the equipment cost (EC) for the SNCR 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.

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 = $ 1,289,883.70 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574.5)

Indirect Capital Costs:

Total Indirect Installation Costs, IC = $ 257,977

=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 = $ 232,179.07

= 15% of DC + IC

Total Plant Cost, D = $ 1,780,039.50 = DC + IC + C

Allowance for Funds During Construction, E = $ - (Assumed zero for SNCR)

Royalty Allowance,F = $ - (Assumed zero for SNCR)

Preproduction Costs, G = $ 35,600.79

= 2% of D + E

Inventory Capital, H =	$	183,472.19	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =		99174	gal/yr	
$Cost_{reagent}$ =		1.85	$/gal	$/gallon (Mundi Price Index for January 2014, United States)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SNCR)	
Total Capital Investment, TCI =	$	1,999,112.48	= 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 SNCR.
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.

Maintenance:

1.5%	of TCI		
Maintenance =	$	29,987	

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

Reagent Consumption (Urea):

$cost_{reagent}$		1.85	$/gallon (As per page i-39 from SNCR manual; CPI ratio applied to reflect 2014 prices)
Annual reagent cost =	$	183,976	= 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)=	0.54	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):	1.48	
Q_B, boiler heat input=	229	MMBtu/hr
P =	9	kw
$Cost_{elec}$ =	0.07	$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)
t_{op} =	8760	hours

Annual electricity cost = P x $Cost_{elect}$ x t_{op} = $ 5,565 per kWh

Water Consumption:

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

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

$$q_{water} = \frac{4m_{sol}}{\rho_{water}}$$

ρ_{water} =	8.345	lb/gal
q_{water} =	0.05165	1,000 gallons/hour

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

$Cost_{water}$ =	8.37	$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial Users)
$	3,786.84	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.4364$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Natural gas	0.00	MMBtu/hr
Coke oven gas	13.44	MMBtu/hr
Total MMBtu/hr	13.44	

Percent usage:

Natural gas	0.00
Coke oven gas	1.00

Additional fuel required:

Natural gas	0.43638	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost		9.44	$/MMBtu
	$	36,086.50	$/yr
Total Natural gas:	$	36,086.50	
Additional Energy Requirement =	$	5,307,425	(Additional heating of exhaust gas required for SNCR operations.)
Total DAC =	$	5,566,826.36	

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 =		9.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n=		20	years
CRF =		0.11	
TCI = Total Capital Investment =	$	1,999,112.48	
IDAC =	$	218,995.73	

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC =	$	5,785,822.09	
Total NO_X removed =		244	tpy

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s R1/R2
NO_x Emission Control Option: SNCR (45% Efficiency)

Site Information

Utility Unit Costs

Electricity, $/kwh	0.07
Interest Rate, %	9.00%
Water, $/1,000 gal	8.37
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

Furnace Fuel Rating, mmBTU/hr	229
NOX Removal Efficiency, η_{NOx}	45%
Cost Year	2014

Incremental Utility Requirements

Electricity, kw	9
Reagent sol, gal/hr	11.38
Water, 1,000 gal/hr	0.08
NG, MMBtu/hr	0.44

Reagent Volume, gallons	99174
Reagent Cost, $/gallon	1.85

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s R1/R2
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT			TOTAL ANNUAL COST				COST EFFECTIVENESS	
Total Direct Capital Cost, DC	$	1,289,884	**Direct Annual Costs**				NOX_{in}, lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger)	$	-	Operating & Supervisory Labor	$38,325			Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.			Maintenance	$29,987			Heater Heat Input, MMBtu/hr	229
			Reagent Consumption	$183,976			Total Operating Time, hrs/yr	8760
			Utilities	$5,565				
			Water Consumption	$3,787			NO_X removed, tpy	243.7
Total Indirect Capital Costs:			Add'l Fuel Usage (Process related)	$36,086.50				
Indirect Capital, IC	$	257,977	Auxilliary Equipment Requirements	$ 5,307,425				
Project Contingency, C	$	232,179	(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)					
Total Plant Cost, D (DC + IC + C)	$	1,780,040						
			Total Direct Annual Costs			$5,605,151		
Allowance for Funds During Constr., E	$	-					**Cost Efficiency:**	
Royalty Allowance,F	$	-					**$/ton NO_X removed**	**$23,896**
Preproduction Costs, G	$	35,601	**Indirect Annual Costs**					
Inventory Capital, H	$	183,472	CRF	0.110				
Initial Catalyst and Chemicals, I	$	-	Total IDAC (CRF x TCI)		$	218,996		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**1,999,112**	**TOTAL ANNUAL COST, TAC (DAC + IDAC)**		**$**	**5,824,147**		

SNCR Design Parameters used for Estimation

Boiler T1/T2 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

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

$$CF_{T1T2} = \frac{Actual2012, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012}$	18.56	MMBtu/hr
Potential	156	MMBtu/hr

$CF_{T1/T2}$= 0.12

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

t_{SNCR} 365 days/yr

CF_{SNCR}= 1.00

CF_{total}= 0.12

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, η_{NOx}	45%	
Stack NO_X =	0.297	lb/MMBtu (Estimated)

Normalized Stoichiometric Ratio, NSR

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

NSR = 1.48

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 1-27 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) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$\dot{m}_{reagent}$ = 36.7 lbs/hr

Aqueous reagent solution mass flow rate:

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

$\dot{m}_{sol}$ = 73.4 lbs/hr

Solution volume flow rate:

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

q_{sol} = 7.73 gph

Aqueous reagent solution storage:

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

$t_{storage}$ = 14.00 days (Assumption from pg. 1-27 in SNCR manual)

V_{tank} = 2598.45 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 2014

Includes: direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include the equipment cost (*EC*) for the SNCR 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.

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 = $ 1,096,558.61 (Chemical Engineering: Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574

Indirect Capital Costs:

Total Indirect Installation Costs, IC = $ 219,312

=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 = $ 197,380.55

= 15% of DC + IC

Total Plant Cost, D = $ 1,513,250.89 = DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)
Royalty Allowance, F =	$	-	(Assumed zero for SNCR)
Preproduction Costs, G =	$	30,265.02	
=		2%	of D + E
Inventory Capital, H =	$	124,985.42	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)
$Vol_{reagent}$ =		67560	gal/yr
$Cost_{reagent}$ =		1.85	$/gal $/gallon (Mundi Price Index for January 2014, United States)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SNCR)
Total Capital Investment, TCI =	$	1,668,501.32	= 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 SNCR.
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.

Maintenance:

1.5%	of TCI	
Maintenance =	$	25,028

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

Reagent Consumption (Urea):

$cost_{reagent}$		1.85	$/gallon (Mundi Price Index for January 2014, United States)
Annual reagent cost =	$	125,329	= q_{sol} x $cost_{reagent}$ x t_{op}

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=	0.54	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):	1.483333333	
Q_B, boiler heat input=	156	MMBtu/hr
P =	6	kw
$Cost_{elec}$ =	0.07	$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)
t_{op} =	8760	hours

Annual electricity cost = P x $Cost_{elect}$ x t_{op} = $ 3,791 per kWh

Water Consumption:

$$q_{water} = \frac{m_{sol}}{\rho_{water}} \left(\frac{C_{ureaSol_{actual}}}{C_{ureaSol_{in}}} - 1 \right)$$

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

$$q_{water} = \frac{4m_{sol}}{\rho_{water}}$$

ρ_{water} =	8.345	lb/gal
q_{water} =	0.03518	1,000 gallons/hour

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

$Cost_{water}$ =		8.37	$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial User
	$	2,579.68	http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.shtml

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.2973$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Coke oven gas	18.56	MMBtu/hr
Natural gas	0	MMBtu/hr
Total MMBtu/hr	18.56	

Percent usage:

Coke oven gas	1.00
Natural gas	0.00

Additional fuel required:

Natural gas	0.29727	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost		9.44	$/MMBtu
	$	24,582.94	$/yr
Total Natural gas:	$	24,582.94	
Additional Energy Requirement =	$	4,075,344	(Additional heating of exhaust gas required for SNCR operations.)
Total DAC =	$	4,256,654.24	

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 =		9.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n=		20	years
CRF =		0.11	
TCI = Total Capital Investment =	$	1,668,501.32	
IDAC =	$	182,778.44	

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC =	$	4,439,432.68	
Total NO_X removed =		166	tpy

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s T1/T2
NO_x Emission Control Option: SNCR (45% Efficiency)

Site Information

Utility Unit Costs

Electricity, $/kwh	0.07
Interest Rate, %	9.00%
Water, $/1,000 gal	8.37
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	2014

Incremental Utility Requirements

Electricity, kw	6
Reagent sol, gal/hr	7.73
Water, 1,000 gal/hr	0.04
NG, MMBtu/hr	0.91660

Reagent Volume, gallons	67560
Reagent Cost, $/gallon	1.85

COMPANY: United States Steel
LOCATION: Clairton
Source: Boiler #s T1/T2
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT							
Total Direct Capital Cost, DC	$	1,096,559					
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	$	219,312					
Project Contingency, C	$	197,381					
Total Plant Cost, D (DC + IC + C)	$	1,513,251					
Allowance for Funds During Constr., E	$	-					
Royalty Allowance,F	$	-					
Preproduction Costs, G	$	30,265					
Inventory Capital, H	$	124,985					
Initial Catalyst and Chemicals, I	$	-					
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**1,668,501**					

TOTAL ANNUAL COST					
Direct Annual Costs					
Operating & Supervisory Labor		$38,325			
Maintenance		$25,028			
Reagent Consumption		$125,329			
Utilities		$3,791			
Water Consumption		$2,580			
Add'l Fuel Usage (Process related)		$24,583			
Auxilliary Equipment Requirements (Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)	$	4,075,344			
Total Direct Annual Costs					$4,294,979
Indirect Annual Costs					
CRF		0.110			
Total IDAC (CRF x TCI)			$	182,778	
TOTAL ANNUAL COST, TAC (DAC + IDAC)			**$**	**4,477,758**	

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.54
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	156
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	166
Cost Efficiency:	
$/ton NO_X removed	**$26,968**

Max 30-Day Rolling Average		
Boiler 1	0.40	lb/MMBtu
Boiler 2	0.31	lb/MMBtu

Proposed 30-day Limit for Boiler 1 (max +20%):	**0.48**	**lb/MMBtu on a 30-day rolling average**
Proposed 30-day Limit for Boiler 2 (max +20%):	**0.37**	**lb/MMBtu on a 30-day rolling average**

Date	B1 LB/MMBTU	B2 LB/MMBTU	B1 30-day avg	B2 30-day avg
1-Jan-14	0.33	0.23		
2-Jan-14	0.30	0.24		
3-Jan-14	0.33	0.27		
4-Jan-14	0.34	0.24		
5-Jan-14	0.31	0.21		
6-Jan-14	0.31	0.24		
7-Jan-14	0.34	0.25		
8-Jan-14	0.37	0.23		
9-Jan-14	0.38	0.23		
10-Jan-14	0.37	0.22		
11-Jan-14	0.34	0.21		
12-Jan-14	0.38	0.25		
13-Jan-14	0.42	0.25		
14-Jan-14	0.41	0.24		
15-Jan-14	0.42	0.29		
16-Jan-14	0.43	0.26		
17-Jan-14	0.39	0.22		
18-Jan-14	0.42	0.24		
19-Jan-14	0.42	0.22		
20-Jan-14	0.43	0.21		
21-Jan-14	0.44	0.23		
22-Jan-14	0.43	0.25		
23-Jan-14	0.43	0.22		
24-Jan-14	0.42	0.24		
25-Jan-14	0.42	0.24		
26-Jan-14	0.43	0.24		
27-Jan-14	0.44	0.24		
28-Jan-14	0.43	0.26		
29-Jan-14	0.43	0.24		
30-Jan-14	0.39	0.23	0.391	0.238
31-Jan-14	0.36	0.20	0.392	0.237
1-Feb-14	0.38	0.21	0.394	0.236
2-Feb-14	0.37	0.21	0.395	0.234
3-Feb-14	0.36	0.24	0.396	0.234
4-Feb-14	0.39	0.21	0.399	0.234
5-Feb-14	0.34	0.19	0.400	0.232
6-Feb-14	0.36	0.23	0.400	0.231
7-Feb-14	0.38	0.24	0.400	0.232
8-Feb-14	0.37	0.24	0.400	0.232
9-Feb-14	0.35	0.21	0.399	0.232
10-Feb-14	0.37	0.23	0.400	0.232
11-Feb-14	0.40	0.25	0.401	0.232
12-Feb-14	0.38	0.24	0.400	0.232
13-Feb-14	0.36	0.20	0.398	0.231
14-Feb-14	0.36	0.20	0.396	0.227
15-Feb-14	0.38	0.22	0.394	0.226
16-Feb-14	0.39	0.24	0.394	0.227
17-Feb-14	0.43	0.25	0.394	0.227
18-Feb-14	0.41	0.22	0.394	0.227
19-Feb-14	0.37	0.21	0.392	0.227
20-Feb-14	0.36	0.22	0.389	0.227
21-Feb-14	0.37	0.20	0.387	0.225
22-Feb-14	0.39	0.21	0.386	0.225
23-Feb-14	0.35	0.22	0.383	0.224
24-Feb-14	0.36	0.25	0.382	0.224
25-Feb-14	0.38	0.23	0.380	0.224
26-Feb-14	0.38	0.23	0.378	0.223
27-Feb-14	0.37	0.24	0.375	0.223
28-Feb-14	0.40	0.24	0.374	0.223
1-Mar-14	0.39	0.23	0.374	0.223
2-Mar-14	0.36	0.23	0.375	0.224
3-Mar-14	0.40	0.25	0.375	0.225

4-Mar-14	0.41	0.23	0.377	0.226
5-Mar-14	0.37	0.22	0.377	0.225
6-Mar-14	0.36	0.22	0.376	0.226
7-Mar-14	0.38	0.21	0.377	0.227
8-Mar-14	0.37	0.21	0.378	0.226
9-Mar-14	0.40	0.23	0.378	0.226
10-Mar-14	0.36	0.19	0.378	0.224
11-Mar-14	0.31	0.19	0.376	0.223
12-Mar-14	0.32	0.23	0.374	0.223
13-Mar-14	0.40	0.28	0.374	0.224
14-Mar-14	0.39	0.21	0.375	0.223
15-Mar-14	0.34	0.22	0.374	0.224
16-Mar-14	0.38	0.26	0.375	0.226
17-Mar-14	0.42	0.25	0.376	0.227
18-Mar-14	0.43	0.24	0.377	0.227
19-Mar-14	0.38	0.22	0.375	0.226
20-Mar-14	0.38	0.24	0.374	0.227
21-Mar-14	0.40	0.25	0.375	0.228
22-Mar-14	0.41	0.23	0.377	0.229
23-Mar-14	0.41	0.27	0.378	0.231
24-Mar-14	0.43	0.26	0.379	0.233
25-Mar-14	0.42	0.23	0.382	0.233
26-Mar-14	0.39	0.28	0.383	0.234
27-Mar-14	0.37	0.28	0.383	0.236
28-Mar-14	0.30	0.22	0.380	0.236
29-Mar-14	0.30	0.23	0.378	0.235
30-Mar-14	0.33	0.27	0.376	0.236
31-Mar-14	0.33	0.24	0.374	0.237
1-Apr-14	0.36	0.26	0.373	0.238
2-Apr-14	0.34	0.25	0.372	0.238
3-Apr-14	0.26	0.20	0.366	0.237
4-Apr-14	0.21	0.20	0.361	0.236
5-Apr-14	0.23	0.23	0.357	0.236
6-Apr-14	0.25	0.24	0.353	0.237
7-Apr-14	0.24	0.21	0.348	0.237
8-Apr-14	0.23	0.23	0.343	0.237
9-Apr-14	0.22	0.22	0.338	0.238
10-Apr-14	0.23	0.21	0.335	0.239
11-Apr-14	0.30	0.20	0.335	0.238
12-Apr-14	0.39	0.23	0.334	0.236
13-Apr-14	0.36	0.23	0.334	0.237
14-Apr-14	0.34	0.21	0.334	0.237
15-Apr-14	0.36	0.24	0.333	0.236
16-Apr-14	0.38	0.26	0.332	0.236
17-Apr-14	0.40	0.25	0.331	0.237
18-Apr-14	0.36	0.24	0.331	0.237
19-Apr-14	0.36	0.24	0.330	0.237
20-Apr-14	0.35	0.25	0.328	0.237
21-Apr-14	0.29	0.23	0.324	0.237
22-Apr-14	0.33	0.23	0.322	0.236
23-Apr-14	0.38	0.26	0.320	0.236
24-Apr-14	0.25	0.17	0.314	0.234
25-Apr-14	0.14	0.10	0.306	0.228
26-Apr-14	0.20	0.11	0.300	0.222
27-Apr-14	0.28	0.09	0.300	0.218
28-Apr-14	0.28	0.09	0.299	0.213
29-Apr-14	0.14	0.09	0.293	0.207
30-Apr-14	0.14	0.09	0.286	0.202
1-May-14	0.14	0.09	0.279	0.196
2-May-14	0.14	0.09	0.272	0.191
3-May-14	0.14	0.09	0.268	0.188
4-May-14	0.15	0.08	0.266	0.184
5-May-14	0.14	0.08	0.263	0.179

6-May-14	0.15	0.09	0.260	0.174
7-May-14	0.23	0.09	0.260	0.170
8-May-14	0.11	0.08	0.256	0.165
9-May-14	0.11	0.08	0.252	0.160
10-May-14	0.11	0.08	0.248	0.156
11-May-14	0.11	0.08	0.242	0.152
12-May-14	0.16	0.08	0.234	0.147
13-May-14	0.16	0.08	0.228	0.142
14-May-14	0.11	0.08	0.220	0.137
15-May-14	0.11	0.08	0.211	0.132
16-May-14	0.12	0.08	0.203	0.126
17-May-14	0.12	0.08	0.193	0.120
18-May-14	0.12	0.08	0.185	0.115
19-May-14	0.12	0.09	0.178	0.110
20-May-14	0.19	0.08	0.172	0.104
21-May-14	0.11	0.07	0.166	0.099
22-May-14	0.11	0.08	0.159	0.094
23-May-14	0.12	0.08	0.150	0.088
24-May-14	0.16	0.08	0.147	0.085
25-May-14	0.14	0.09	0.147	0.084
26-May-14	0.14	0.09	0.145	0.084
27-May-14	0.13	0.08	0.140	0.083
28-May-14	0.12	0.08	0.135	0.083
29-May-14	0.12	0.08	0.134	0.082
30-May-14	0.12	0.08	0.133	0.082
31-May-14	0.16	0.08	0.134	0.082
1-Jun-14	0.16	0.08	0.134	0.082
2-Jun-14	0.17	0.08	0.135	0.081
3-Jun-14	0.14	0.08	0.135	0.081
4-Jun-14	0.13	0.08	0.135	0.081
5-Jun-14	0.13	0.08	0.134	0.081
6-Jun-14	0.17	0.09	0.132	0.081
7-Jun-14	0.19	0.09	0.135	0.081
8-Jun-14	0.16	0.08	0.137	0.081
9-Jun-14	0.16	0.08	0.138	0.081
10-Jun-14	0.17	0.08	0.140	0.081
11-Jun-14	0.05	0.16	0.136	0.084
12-Jun-14	0.00	0.17	0.131	0.087
13-Jun-14	0.01	0.17	0.128	0.090
14-Jun-14	0.00	0.21	0.124	0.094
15-Jun-14	0.00	0.21	0.121	0.099
16-Jun-14	0.00	0.20	0.117	0.103
17-Jun-14	0.00	0.20	0.113	0.107
18-Jun-14	0.02	0.20	0.109	0.111
19-Jun-14	0.00	0.19	0.103	0.114
20-Jun-14	0.00	0.19	0.100	0.119
21-Jun-14	0.01	0.20	0.096	0.122
22-Jun-14	0.00	0.20	0.092	0.126
23-Jun-14	0.00	0.20	0.087	0.130
24-Jun-14	0.00	0.19	0.083	0.134
25-Jun-14	0.01	0.19	0.078	0.137
26-Jun-14	0.01	0.20	0.075	0.141
27-Jun-14	0.01	0.20	0.071	0.146
28-Jun-14	0.01	0.20	0.068	0.150
29-Jun-14	0.01	0.20	0.064	0.154
30-Jun-14	0.01	0.20	0.059	0.157
1-Jul-14	0.01	0.19	0.054	0.161
2-Jul-14	0.01	0.20	0.048	0.165
3-Jul-14	0.02	0.20	0.044	0.169
4-Jul-14	0.00	0.22	0.040	0.173
5-Jul-14	0.00	0.22	0.036	0.178
6-Jul-14	0.01	0.21	0.030	0.182
7-Jul-14	0.01	0.20	0.024	0.186

8-Jul-14	0.01	0.19	0.019	0.189
9-Jul-14	0.11	0.16	0.017	0.192
10-Jul-14	0.16	0.10	0.017	0.192
11-Jul-14	0.15	0.10	0.021	0.190
12-Jul-14	0.15	0.10	0.026	0.188
13-Jul-14	0.15	0.09	0.030	0.185
14-Jul-14	0.14	0.09	0.035	0.181
15-Jul-14	0.14	0.10	0.039	0.178
16-Jul-14	0.13	0.10	0.044	0.174
17-Jul-14	0.14	0.10	0.048	0.171
18-Jul-14	0.17	0.09	0.053	0.167
19-Jul-14	0.16	0.09	0.058	0.164
20-Jul-14	0.14	0.09	0.063	0.160
21-Jul-14	0.14	0.09	0.067	0.157
22-Jul-14	0.13	0.09	0.071	0.153
23-Jul-14	0.14	0.09	0.075	0.150
24-Jul-14	0.15	0.09	0.080	0.146
25-Jul-14	0.14	0.09	0.085	0.143
26-Jul-14	0.20	0.09	0.091	0.139
27-Jul-14	0.18	0.09	0.096	0.136
28-Jul-14	0.17	0.09	0.102	0.132
29-Jul-14	0.16	0.09	0.107	0.128
30-Jul-14	0.20	0.10	0.114	0.125
31-Jul-14	0.18	0.09	0.120	0.122
1-Aug-14	0.16	0.09	0.125	0.118
2-Aug-14	0.17	0.08	0.130	0.114
3-Aug-14	0.16	0.09	0.135	0.110
4-Aug-14	0.16	0.09	0.140	0.105
5-Aug-14	0.13	0.09	0.144	0.101
6-Aug-14	0.11	0.09	0.148	0.097
7-Aug-14	0.12	0.09	0.151	0.094
8-Aug-14	0.15	0.09	0.153	0.092
9-Aug-14	0.16	0.09	0.153	0.091
10-Aug-14	0.13	0.08	0.152	0.091
11-Aug-14	0.12	0.08	0.151	0.090
12-Aug-14	0.12	0.08	0.150	0.090
13-Aug-14	0.16	0.09	0.151	0.090
14-Aug-14	0.19	0.10	0.153	0.090
15-Aug-14	0.19	0.10	0.155	0.090
16-Aug-14	0.19	0.10	0.156	0.090
17-Aug-14	0.18	0.09	0.157	0.090
18-Aug-14	0.17	0.09	0.157	0.090
19-Aug-14	0.17	0.09	0.158	0.090
20-Aug-14	0.17	0.09	0.159	0.090
21-Aug-14	0.13	0.09	0.159	0.090
22-Aug-14	0.18	0.09	0.161	0.089
23-Aug-14	0.19	0.09	0.162	0.089
24-Aug-14	0.15	0.10	0.162	0.089
25-Aug-14	0.15	0.10	0.161	0.090
26-Aug-14	0.14	0.10	0.160	0.090
27-Aug-14	0.14	0.09	0.158	0.090
28-Aug-14	0.13	0.09	0.157	0.090
29-Aug-14	0.14	0.10	0.155	0.090
30-Aug-14	0.13	0.10	0.154	0.090
31-Aug-14	0.15	0.09	0.154	0.090
1-Sep-14	0.17	0.09	0.153	0.090
2-Sep-14	0.17	0.09	0.154	0.090
3-Sep-14	0.15	0.10	0.154	0.091
4-Sep-14	0.14	0.10	0.154	0.091
5-Sep-14	0.15	0.09	0.155	0.091
6-Sep-14	0.17	0.09	0.156	0.091
7-Sep-14	0.16	0.10	0.157	0.092
8-Sep-14	0.16	0.10	0.157	0.092

9-Sep-14	0.16	0.10	0.158	0.093
10-Sep-14	0.16	0.09	0.159	0.093
11-Sep-14	0.13	0.09	0.159	0.093
12-Sep-14	0.16	0.10	0.159	0.093
13-Sep-14	0.18	0.11	0.158	0.094
14-Sep-14	0.20	0.11	0.159	0.094
15-Sep-14	0.20	0.10	0.159	0.094
16-Sep-14	0.19	0.10	0.160	0.095
17-Sep-14	0.19	0.11	0.160	0.095
18-Sep-14	0.17	0.11	0.160	0.096
19-Sep-14	0.14	0.10	0.159	0.096
20-Sep-14	0.14	0.10	0.159	0.097
21-Sep-14	0.15	0.10	0.158	0.097
22-Sep-14	0.17	0.10	0.158	0.097
23-Sep-14	0.17	0.11	0.158	0.098
24-Sep-14	0.17	0.10	0.159	0.098
25-Sep-14	0.14	0.09	0.159	0.098
26-Sep-14	0.14	0.09	0.159	0.098
27-Sep-14	0.14	0.10	0.159	0.098
28-Sep-14	0.14	0.10	0.159	0.098
29-Sep-14	0.14	0.10	0.159	0.098
30-Sep-14	0.28	0.03	0.164	0.096
1-Oct-14	0.34	0.00	0.170	0.093
2-Oct-14	0.35	0.00	0.175	0.090
3-Oct-14	0.33	0.00	0.181	0.087
4-Oct-14	0.38	0.00	0.189	0.084
5-Oct-14	0.44	0.00	0.199	0.081
6-Oct-14	0.39	0.01	0.207	0.079
7-Oct-14	0.37	0.00	0.214	0.075
8-Oct-14	0.39	0.00	0.221	0.072
9-Oct-14	0.40	0.01	0.229	0.069
10-Oct-14	0.38	0.00	0.237	0.066
11-Oct-14	0.40	0.00	0.246	0.063
12-Oct-14	0.39	0.00	0.253	0.060
13-Oct-14	0.36	0.00	0.259	0.056
14-Oct-14	0.35	0.00	0.264	0.053
15-Oct-14	0.35	0.00	0.269	0.049
16-Oct-14	0.35	0.00	0.274	0.046
17-Oct-14	0.36	0.00	0.280	0.043
18-Oct-14	0.38	0.00	0.287	0.039
19-Oct-14	0.39	0.00	0.295	0.036
20-Oct-14	0.38	0.00	0.303	0.033
21-Oct-14	0.36	0.00	0.310	0.030
22-Oct-14	0.39	0.00	0.317	0.026
23-Oct-14	0.38	0.00	0.324	0.023
24-Oct-14	0.38	0.00	0.331	0.020
25-Oct-14	0.37	0.00	0.339	0.017
26-Oct-14	0.39	0.01	0.347	0.014
27-Oct-14	0.37	0.19	0.355	0.017
28-Oct-14	0.34	0.23	0.362	0.022
29-Oct-14	0.37	0.24	0.369	0.026
30-Oct-14	0.37	0.24	0.372	0.033
31-Oct-14	0.38	0.23	0.374	0.041
1-Nov-14	0.39	0.23	0.375	0.048
2-Nov-14	0.41	0.24	0.378	0.056
3-Nov-14	0.38	0.23	0.378	0.064
4-Nov-14	0.38	0.23	0.375	0.071
5-Nov-14	0.35	0.20	0.374	0.078
6-Nov-14	0.35	0.21	0.374	0.084
7-Nov-14	0.37	0.24	0.373	0.092
8-Nov-14	0.40	0.24	0.373	0.100
9-Nov-14	0.39	0.22	0.373	0.107
10-Nov-14	0.39	0.22	0.373	0.115

11-Nov-14	0.39	0.23	0.373	0.122
12-Nov-14	0.39	0.23	0.375	0.130
13-Nov-14	0.42	0.25	0.377	0.138
14-Nov-14	0.38	0.25	0.378	0.147
15-Nov-14	0.40	0.27	0.380	0.155
16-Nov-14	0.42	0.24	0.382	0.163
17-Nov-14	0.37	0.22	0.381	0.170
18-Nov-14	0.40	0.24	0.382	0.178
19-Nov-14	0.38	0.23	0.382	0.186
20-Nov-14	0.38	0.22	0.383	0.193
21-Nov-14	0.40	0.23	0.383	0.200
22-Nov-14	0.39	0.22	0.384	0.208
23-Nov-14	0.39	0.21	0.384	0.214
24-Nov-14	0.38	0.21	0.384	0.221
25-Nov-14	0.38	0.23	0.384	0.229
26-Nov-14	0.37	0.22	0.384	0.230
27-Nov-14	0.39	0.23	0.386	0.230
28-Nov-14	0.38	0.23	0.386	0.229
29-Nov-14	0.40	0.21	0.387	0.229
30-Nov-14	0.41	0.21	0.388	0.228
1-Dec-14	0.42	0.23	0.389	0.228
2-Dec-14	0.42	0.24	0.389	0.228
3-Dec-14	0.40	0.22	0.390	0.228
4-Dec-14	0.44	0.25	0.392	0.228
5-Dec-14	0.39	0.23	0.393	0.229
6-Dec-14	0.37	0.22	0.394	0.230
7-Dec-14	0.41	0.25	0.395	0.230
8-Dec-14	0.41	0.22	0.395	0.230
9-Dec-14	0.37	0.21	0.394	0.229
10-Dec-14	0.35	0.22	0.393	0.230
11-Dec-14	0.36	0.24	0.392	0.230
12-Dec-14	0.36	0.24	0.391	0.230
13-Dec-14	0.39	0.22	0.390	0.229
14-Dec-14	0.39	0.21	0.391	0.228
15-Dec-14	0.41	0.22	0.391	0.226
16-Dec-14	0.28	0.20	0.386	0.225
17-Dec-14	0.23	0.18	0.382	0.224
18-Dec-14	0.33	0.21	0.379	0.222
19-Dec-14	0.38	0.22	0.379	0.222
20-Dec-14	0.39	0.22	0.379	0.222
21-Dec-14	0.40	0.22	0.379	0.222
22-Dec-14	0.42	0.23	0.380	0.223
23-Dec-14	0.42	0.22	0.381	0.223
24-Dec-14	0.40	0.21	0.382	0.223
25-Dec-14	0.44	0.25	0.384	0.223
26-Dec-14	0.44	0.25	0.386	0.225
27-Dec-14	0.43	0.22	0.387	0.224
28-Dec-14	0.43	0.23	0.389	0.225
29-Dec-14	0.43	0.24	0.390	0.225
30-Dec-14	0.43	0.24	0.391	0.226
31-Dec-14	0.41	0.24	0.390	0.227
1-Jan-15	0.45	0.24	0.392	0.227
2-Jan-15	0.40	0.23	0.392	0.227
3-Jan-15	0.36	0.21	0.389	0.226
4-Jan-15	0.40	0.21	0.390	0.225
5-Jan-15	0.45	0.26	0.392	0.226
6-Jan-15	0.42	0.24	0.393	0.226
7-Jan-15	0.34	0.26	0.390	0.227
8-Jan-15	0.36	0.26	0.390	0.229
9-Jan-15	0.36	0.25	0.390	0.230
10-Jan-15	0.36	0.27	0.390	0.231
11-Jan-15	0.39	0.26	0.391	0.231
12-Jan-15	0.41	0.23	0.392	0.232

13-Jan-15	0.40	0.25	0.392	0.233
14-Jan-15	0.39	0.24	0.391	0.234
15-Jan-15	0.39	0.25	0.395	0.236
16-Jan-15	0.38	0.23	0.400	0.237
17-Jan-15	0.42	0.24	0.403	0.238
18-Jan-15	0.39	0.22	0.403	0.238
19-Jan-15	0.39	0.23	0.403	0.238
20-Jan-15	0.36	0.22	0.402	0.238
21-Jan-15	0.33	0.20	0.399	0.237
22-Jan-15	0.35	0.22	0.397	0.237
23-Jan-15	0.36	0.23	0.396	0.238
24-Jan-15	0.38	0.23	0.394	0.237
25-Jan-15	0.36	0.22	0.391	0.236
26-Jan-15	0.36	0.22	0.389	0.236
27-Jan-15	0.35	0.23	0.386	0.236
28-Jan-15	0.36	0.23	0.384	0.235
29-Jan-15	0.34	0.21	0.381	0.235
30-Jan-15	0.35	0.23	0.379	0.234
31-Jan-15	0.37	0.24	0.376	0.234
1-Feb-15	0.36	0.21	0.375	0.234
2-Feb-15	0.34	0.20	0.374	0.233
3-Feb-15	0.36	0.24	0.373	0.234
4-Feb-15	0.35	0.21	0.369	0.233
5-Feb-15	0.36	0.23	0.367	0.232
6-Feb-15	0.37	0.22	0.369	0.231
7-Feb-15	0.35	0.20	0.368	0.229
8-Feb-15	0.31	0.19	0.367	0.227
9-Feb-15	0.31	0.21	0.365	0.226
10-Feb-15	0.35	0.22	0.363	0.224
11-Feb-15	0.35	0.21	0.361	0.224
12-Feb-15	0.34	0.22	0.359	0.223
13-Feb-15	0.32	0.23	0.357	0.222
14-Feb-15	0.35	0.22	0.356	0.221
15-Feb-15	0.36	0.24	0.355	0.221
16-Feb-15	0.36	0.22	0.353	0.221
17-Feb-15	0.36	0.23	0.352	0.221
18-Feb-15	0.36	0.23	0.351	0.221
19-Feb-15	0.36	0.24	0.351	0.222
20-Feb-15	0.36	0.23	0.352	0.223
21-Feb-15	0.34	0.21	0.352	0.222
22-Feb-15	0.35	0.22	0.352	0.222
23-Feb-15	0.37	0.24	0.351	0.222
24-Feb-15	0.35	0.22	0.351	0.223
25-Feb-15	0.34	0.22	0.351	0.222
26-Feb-15	0.35	0.23	0.350	0.222
27-Feb-15	0.36	0.25	0.350	0.223
28-Feb-15	0.38	0.24	0.352	0.224
1-Mar-15	0.37	0.22	0.352	0.223
2-Mar-15	0.37	0.22	0.352	0.223
3-Mar-15	0.36	0.21	0.352	0.223
4-Mar-15	0.32	0.21	0.352	0.223
5-Mar-15	0.34	0.24	0.351	0.223
6-Mar-15	0.34	0.24	0.351	0.224
7-Mar-15	0.34	0.22	0.350	0.224
8-Mar-15	0.35	0.21	0.350	0.223
9-Mar-15	0.35	0.21	0.349	0.224
10-Mar-15	0.34	0.21	0.350	0.224
11-Mar-15	0.33	0.21	0.351	0.224
12-Mar-15	0.34	0.23	0.351	0.224
13-Mar-15	0.32	0.23	0.350	0.225
14-Mar-15	0.30	0.20	0.349	0.224
15-Mar-15	0.38	0.22	0.351	0.224
16-Mar-15	0.39	0.21	0.352	0.223

17-Mar-15	0.39	0.21	0.353	0.222
18-Mar-15	0.35	0.23	0.353	0.222
19-Mar-15	0.35	0.20	0.352	0.222
20-Mar-15	0.33	0.19	0.351	0.220
21-Mar-15	0.33	0.19	0.350	0.219
22-Mar-15	0.40	0.22	0.351	0.219
23-Mar-15	0.45	0.24	0.355	0.220
24-Mar-15	0.40	0.22	0.356	0.220
25-Mar-15	0.33	0.20	0.355	0.218
26-Mar-15	0.30	0.19	0.353	0.217
27-Mar-15	0.33	0.24	0.353	0.218
28-Mar-15	0.38	0.26	0.354	0.219
29-Mar-15	0.46	0.23	0.357	0.218
30-Mar-15	0.41	0.21	0.358	0.217
31-Mar-15	0.37	0.22	0.358	0.217
1-Apr-15	0.36	0.21	0.358	0.217
2-Apr-15	0.32	0.19	0.357	0.216
3-Apr-15	0.35	0.20	0.358	0.216
4-Apr-15	0.42	0.26	0.360	0.216
5-Apr-15	0.42	0.24	0.363	0.216
6-Apr-15	0.40	0.21	0.365	0.216
7-Apr-15	0.39	0.19	0.366	0.215
8-Apr-15	0.37	0.18	0.367	0.215
9-Apr-15	0.33	0.18	0.367	0.214
10-Apr-15	0.34	0.17	0.367	0.213
11-Apr-15	0.42	0.21	0.370	0.212
12-Apr-15	0.44	0.22	0.374	0.211
13-Apr-15	0.36	0.18	0.376	0.211
14-Apr-15	0.36	0.19	0.375	0.210
15-Apr-15	0.39	0.22	0.375	0.210
16-Apr-15	0.34	0.19	0.374	0.210
17-Apr-15	0.27	0.18	0.371	0.208
18-Apr-15	0.22	0.18	0.367	0.207
19-Apr-15	0.37	0.19	0.368	0.207
20-Apr-15	0.32	0.18	0.368	0.207
21-Apr-15	0.30	0.18	0.364	0.206
22-Apr-15	0.30	0.19	0.359	0.204
23-Apr-15	0.33	0.20	0.357	0.203
24-Apr-15	0.33	0.18	0.357	0.203
25-Apr-15	0.31	0.21	0.357	0.203
26-Apr-15	0.30	0.22	0.356	0.203
27-Apr-15	0.21	0.21	0.350	0.201
28-Apr-15	0.17	0.20	0.340	0.200
29-Apr-15	0.16	0.18	0.332	0.199
30-Apr-15	0.15	0.14	0.325	0.197
1-May-15	0.15	0.08	0.318	0.192
2-May-15	0.16	0.08	0.312	0.188
3-May-15	0.16	0.08	0.306	0.184
4-May-15	0.15	0.08	0.297	0.178
5-May-15	0.15	0.08	0.288	0.173
6-May-15	0.14	0.08	0.279	0.168
7-May-15	0.13	0.08	0.270	0.164
8-May-15	0.14	0.09	0.263	0.161
9-May-15	0.13	0.08	0.256	0.158
10-May-15	0.14	0.08	0.250	0.155
11-May-15	0.13	0.08	0.240	0.151
12-May-15	0.15	0.08	0.230	0.146
13-May-15	0.18	0.09	0.224	0.143
14-May-15	0.16	0.09	0.218	0.140
15-May-15	0.15	0.08	0.209	0.135
16-May-15	0.14	0.08	0.203	0.132
17-May-15	0.13	0.08	0.198	0.128
18-May-15	0.12	0.08	0.194	0.125

19-May-15	0.12	0.08	0.186	0.121
20-May-15	0.13	0.08	0.180	0.118
21-May-15	0.13	0.09	0.175	0.115
22-May-15	0.14	0.09	0.169	0.112
23-May-15	0.14	0.09	0.163	0.108
24-May-15	0.14	0.08	0.157	0.105
25-May-15	0.12	0.08	0.151	0.100
26-May-15	0.12	0.08	0.145	0.096
27-May-15	0.12	0.08	0.142	0.091
28-May-15	0.12	0.08	0.140	0.087
29-May-15	0.12	0.08	0.139	0.084
30-May-15	0.12	0.07	0.138	0.081
31-May-15	0.12	0.08	0.137	0.081
1-Jun-15	0.12	0.08	0.135	0.081
2-Jun-15	0.12	0.08	0.134	0.081
3-Jun-15	0.12	0.08	0.133	0.082
4-Jun-15	0.12	0.08	0.132	0.082
5-Jun-15	0.12	0.08	0.132	0.082
6-Jun-15	0.12	0.08	0.131	0.082
7-Jun-15	0.18	0.08	0.133	0.082
8-Jun-15	0.06	0.17	0.130	0.084
9-Jun-15	0.00	0.21	0.126	0.089
10-Jun-15	0.00	0.21	0.122	0.093
11-Jun-15	0.00	0.21	0.117	0.097
12-Jun-15	0.00	0.21	0.111	0.101
13-Jun-15	0.00	0.20	0.106	0.105
14-Jun-15	0.00	0.20	0.101	0.109
15-Jun-15	0.00	0.20	0.096	0.113
16-Jun-15	0.00	0.21	0.092	0.117
17-Jun-15	0.00	0.21	0.088	0.121
18-Jun-15	0.01	0.20	0.085	0.125
19-Jun-15	0.00	0.21	0.080	0.129
20-Jun-15	0.00	0.20	0.076	0.133
21-Jun-15	0.00	0.20	0.071	0.137
22-Jun-15	0.00	0.19	0.067	0.140
23-Jun-15	0.00	0.20	0.062	0.144
24-Jun-15	0.00	0.21	0.058	0.148
25-Jun-15	0.00	0.23	0.054	0.153
26-Jun-15	0.00	0.20	0.051	0.157
27-Jun-15	0.00	0.20	0.047	0.161
28-Jun-15	0.00	0.21	0.043	0.166
29-Jun-15	0.02	0.21	0.039	0.170
30-Jun-15	0.00	0.20	0.036	0.174
1-Jul-15	0.00	0.20	0.032	0.179
2-Jul-15	0.00	0.21	0.028	0.183
3-Jul-15	0.00	0.21	0.024	0.187
4-Jul-15	0.00	0.20	0.020	0.191
5-Jul-15	0.00	0.21	0.016	0.195
6-Jul-15	0.00	0.20	0.012	0.199
7-Jul-15	0.00	0.20	0.006	0.203
8-Jul-15	0.00	0.20	0.004	0.204
9-Jul-15	0.00	0.19	0.004	0.204
10-Jul-15	0.00	0.21	0.004	0.203
11-Jul-15	0.00	0.21	0.004	0.203
12-Jul-15	0.00	0.21	0.004	0.203
13-Jul-15	0.00	0.19	0.004	0.203
14-Jul-15	0.03	0.20	0.005	0.203
15-Jul-15	0.01	0.21	0.005	0.203
16-Jul-15	0.00	0.22	0.005	0.204
17-Jul-15	0.00	0.20	0.005	0.204
18-Jul-15	0.00	0.20	0.005	0.204
19-Jul-15	0.00	0.19	0.005	0.203
20-Jul-15	0.00	0.20	0.005	0.203

21-Jul-15	0.00	0.20	0.005	0.203
22-Jul-15	0.00	0.22	0.005	0.204
23-Jul-15	0.00	0.22	0.005	0.205
24-Jul-15	0.00	0.21	0.005	0.204
25-Jul-15	0.00	0.21	0.005	0.204
26-Jul-15	0.00	0.20	0.005	0.204
27-Jul-15	0.00	0.20	0.005	0.204
28-Jul-15	0.00	0.20	0.005	0.203
29-Jul-15	0.00	0.20	0.004	0.203
30-Jul-15	0.01	0.21	0.005	0.204
31-Jul-15	0.00	0.22	0.005	0.204
1-Aug-15	0.00	0.21	0.005	0.204
2-Aug-15	0.00	0.21	0.005	0.204
3-Aug-15	0.00	0.21	0.005	0.205
4-Aug-15	0.00	0.21	0.005	0.205
5-Aug-15	0.00	0.22	0.005	0.205
6-Aug-15	0.01	0.22	0.005	0.206
7-Aug-15	0.00	0.22	0.005	0.207
8-Aug-15	0.00	0.21	0.005	0.207
9-Aug-15	0.00	0.21	0.005	0.207
10-Aug-15	0.00	0.20	0.005	0.207
11-Aug-15	0.00	0.21	0.005	0.207
12-Aug-15	0.00	0.21	0.005	0.208
13-Aug-15	0.00	0.22	0.004	0.209
14-Aug-15	0.00	0.22	0.004	0.209
15-Aug-15	0.00	0.21	0.004	0.209
16-Aug-15	0.00	0.21	0.004	0.209
17-Aug-15	0.00	0.21	0.004	0.209
18-Aug-15	0.00	0.20	0.004	0.209
19-Aug-15	0.01	0.20	0.004	0.209
20-Aug-15	0.00	0.20	0.004	0.209
21-Aug-15	0.00	0.22	0.004	0.209
22-Aug-15	0.00	0.22	0.004	0.209
23-Aug-15	0.01	0.20	0.004	0.209
24-Aug-15	0.14	0.13	0.009	0.206
25-Aug-15	0.18	0.09	0.015	0.203
26-Aug-15	0.22	0.10	0.022	0.199
27-Aug-15	0.25	0.10	0.030	0.196
28-Aug-15	0.22	0.06	0.037	0.191
29-Aug-15	0.23	0.00	0.045	0.185
30-Aug-15	0.21	0.00	0.052	0.177
31-Aug-15	0.20	0.00	0.058	0.170
1-Sep-15	0.21	0.00	0.065	0.164
2-Sep-15	0.23	0.00	0.073	0.157
3-Sep-15	0.24	0.00	0.081	0.150
4-Sep-15	0.24	0.01	0.089	0.143
5-Sep-15	0.21	0.00	0.095	0.136
6-Sep-15	0.26	0.00	0.104	0.129
7-Sep-15	0.28	0.00	0.113	0.122
8-Sep-15	0.24	0.00	0.121	0.115
9-Sep-15	0.20	0.00	0.128	0.108
10-Sep-15	0.21	0.00	0.134	0.102
11-Sep-15	0.21	0.00	0.141	0.095
12-Sep-15	0.23	0.00	0.149	0.087
13-Sep-15	0.26	0.00	0.157	0.080
14-Sep-15	0.31	0.01	0.168	0.074
15-Sep-15	0.26	0.00	0.176	0.067
16-Sep-15	0.21	0.00	0.183	0.060
17-Sep-15	0.30	0.00	0.193	0.054
18-Sep-15	0.22	0.00	0.200	0.047
19-Sep-15	0.24	0.00	0.208	0.041
20-Sep-15	0.24	0.00	0.216	0.034
21-Sep-15	0.29	0.00	0.225	0.026

22-Sep-15	0.27	0.00	0.234	0.020
23-Sep-15	0.28	0.01	0.239	0.015
24-Sep-15	0.19	0.00	0.239	0.012
25-Sep-15	0.20	0.00	0.238	0.009
26-Sep-15	0.26	0.00	0.239	0.006
27-Sep-15	0.36	0.00	0.243	0.004
28-Sep-15	0.28	0.00	0.245	0.004
29-Sep-15	0.17	0.00	0.243	0.004
30-Sep-15	0.19	0.00	0.243	0.004
1-Oct-15	0.32	0.01	0.247	0.004
2-Oct-15	0.34	0.00	0.250	0.004
3-Oct-15	0.38	0.00	0.255	0.004
4-Oct-15	0.38	0.00	0.260	0.004
5-Oct-15	0.38	0.00	0.265	0.004
6-Oct-15	0.33	0.00	0.268	0.004
7-Oct-15	0.29	0.00	0.268	0.004
8-Oct-15	0.30	0.01	0.270	0.004
9-Oct-15	0.25	0.12	0.272	0.008
10-Oct-15	0.25	0.20	0.273	0.014
11-Oct-15	0.24	0.21	0.274	0.021
12-Oct-15	0.17	0.23	0.272	0.029
13-Oct-15	0.24	0.16	0.271	0.034
14-Oct-15	0.24	0.18	0.269	0.039
15-Oct-15	0.29	0.20	0.270	0.046
16-Oct-15	0.36	0.21	0.275	0.053
17-Oct-15	0.35	0.22	0.277	0.060
18-Oct-15	0.35	0.23	0.281	0.067
19-Oct-15	0.34	0.22	0.284	0.074
20-Oct-15	0.34	0.20	0.288	0.081
21-Oct-15	0.34	0.20	0.289	0.088
22-Oct-15	0.33	0.19	0.292	0.094
23-Oct-15	0.35	0.21	0.294	0.101
24-Oct-15	0.34	0.21	0.299	0.108
25-Oct-15	0.36	0.21	0.304	0.114
26-Oct-15	0.35	0.26	0.308	0.123
27-Oct-15	0.36	0.22	0.307	0.130
28-Oct-15	0.31	0.20	0.309	0.137
29-Oct-15	0.35	0.21	0.315	0.144
30-Oct-15	0.37	0.24	0.320	0.152
31-Oct-15	0.39	0.22	0.323	0.159
1-Nov-15	0.37	0.20	0.324	0.165
2-Nov-15	0.36	0.22	0.323	0.173
3-Nov-15	0.34	0.21	0.322	0.180
4-Nov-15	0.33	0.22	0.320	0.187
5-Nov-15	0.33	0.20	0.320	0.193
6-Nov-15	0.28	0.20	0.320	0.200
7-Nov-15	0.28	0.22	0.319	0.207
8-Nov-15	0.30	0.23	0.321	0.211
9-Nov-15	0.28	0.21	0.322	0.211
10-Nov-15	0.24	0.19	0.322	0.210
11-Nov-15	0.25	0.20	0.324	0.209
12-Nov-15	0.24	0.20	0.324	0.211
13-Nov-15	0.28	0.22	0.325	0.212
14-Nov-15	0.30	0.22	0.326	0.213
15-Nov-15	0.28	0.21	0.323	0.213
16-Nov-15	0.27	0.21	0.320	0.213
17-Nov-15	0.28	0.19	0.318	0.212
18-Nov-15	0.24	0.19	0.315	0.211
19-Nov-15	0.24	0.19	0.311	0.210
20-Nov-15	0.28	0.22	0.309	0.211
21-Nov-15	0.29	0.24	0.308	0.213
22-Nov-15	0.31	0.22	0.307	0.213
23-Nov-15	0.32	0.24	0.306	0.214

24-Nov-15	0.32	0.22	0.305	0.215
25-Nov-15	0.31	0.21	0.303	0.213
26-Nov-15	0.31	0.20	0.302	0.212
27-Nov-15	0.28	0.20	0.301	0.212
28-Nov-15	0.26	0.19	0.297	0.212
29-Nov-15	0.28	0.22	0.295	0.211
30-Nov-15	0.29	0.20	0.291	0.210
1-Dec-15	0.29	0.18	0.289	0.209
2-Dec-15	0.28	0.19	0.286	0.209
3-Dec-15	0.29	0.25	0.284	0.210
4-Dec-15	0.27	0.25	0.282	0.211
5-Dec-15	0.28	0.24	0.280	0.212
6-Dec-15	0.29	0.21	0.281	0.213
7-Dec-15	0.29	0.21	0.281	0.212
8-Dec-15	0.30	0.21	0.281	0.212
9-Dec-15	0.31	0.20	0.282	0.211
10-Dec-15	0.29	0.19	0.284	0.212
11-Dec-15	0.28	0.19	0.285	0.211
12-Dec-15	0.27	0.17	0.286	0.210
13-Dec-15	0.27	0.17	0.285	0.209
14-Dec-15	0.26	0.18	0.284	0.207
15-Dec-15	0.28	0.18	0.284	0.206
16-Dec-15	0.26	0.16	0.284	0.204
17-Dec-15	0.28	0.19	0.284	0.204
18-Dec-15	0.30	0.24	0.286	0.206
19-Dec-15	0.33	0.25	0.289	0.208
20-Dec-15	0.33	0.21	0.291	0.208
21-Dec-15	0.31	0.18	0.291	0.206
22-Dec-15	0.28	0.16	0.290	0.204
23-Dec-15	0.27	0.17	0.288	0.201
24-Dec-15	0.25	0.18	0.286	0.200
25-Dec-15	0.26	0.19	0.284	0.199
26-Dec-15	0.26	0.19	0.283	0.199
27-Dec-15	0.25	0.19	0.282	0.199
28-Dec-15	0.27	0.21	0.282	0.199
29-Dec-15	0.27	0.20	0.281	0.198
30-Dec-15	0.28	0.20	0.281	0.198
31-Dec-15	0.29	0.21	0.281	0.199
1-Jan-16	0.30	0.22	0.282	0.200
2-Jan-16	0.27	0.21	0.281	0.199
3-Jan-16	0.31	0.22	0.282	0.198
4-Jan-16	0.32	0.23	0.284	0.198
5-Jan-16	0.33	0.23	0.285	0.198
6-Jan-16	0.33	0.21	0.287	0.198
7-Jan-16	0.33	0.22	0.288	0.199
8-Jan-16	0.31	0.23	0.288	0.199
9-Jan-16	0.30	0.20	0.288	0.200
10-Jan-16	0.30	0.22	0.289	0.200
11-Jan-16	0.34	0.25	0.291	0.203
12-Jan-16	0.33	0.22	0.293	0.205
13-Jan-16	0.34	0.24	0.296	0.207
14-Jan-16	0.33	0.22	0.297	0.208
15-Jan-16	0.30	0.20	0.299	0.210
16-Jan-16	0.30	0.22	0.299	0.211
17-Jan-16	0.32	0.24	0.300	0.210
18-Jan-16	0.34	0.28	0.300	0.211
19-Jan-16	0.35	0.26	0.301	0.213
20-Jan-16	0.35	0.25	0.302	0.215
21-Jan-16	0.36	0.23	0.305	0.217
22-Jan-16	0.35	0.22	0.308	0.219
23-Jan-16	0.35	0.22	0.311	0.220
24-Jan-16	0.35	0.22	0.314	0.222
25-Jan-16	0.35	0.21	0.317	0.222

26-Jan-16	0.32	0.20	0.319	0.223
27-Jan-16	0.33	0.21	0.321	0.223
28-Jan-16	0.33	0.23	0.324	0.224
29-Jan-16	0.32	0.22	0.325	0.225
30-Jan-16	0.34	0.23	0.326	0.225
31-Jan-16	0.32	0.19	0.327	0.224
1-Feb-16	0.31	0.19	0.328	0.224
2-Feb-16	0.32	0.22	0.329	0.224
3-Feb-16	0.30	0.19	0.328	0.222
4-Feb-16	0.32	0.23	0.327	0.222
5-Feb-16	0.34	0.24	0.328	0.223
6-Feb-16	0.34	0.22	0.328	0.223
7-Feb-16	0.33	0.22	0.329	0.223
8-Feb-16	0.31	0.21	0.329	0.223
9-Feb-16	0.32	0.21	0.330	0.223
10-Feb-16	0.33	0.23	0.330	0.222
11-Feb-16	0.35	0.24	0.331	0.223
12-Feb-16	0.36	0.23	0.331	0.223
13-Feb-16	0.37	0.25	0.333	0.224
14-Feb-16	0.35	0.23	0.334	0.225
15-Feb-16	0.34	0.21	0.335	0.224
16-Feb-16	0.34	0.21	0.336	0.224
17-Feb-16	0.35	0.22	0.336	0.222
18-Feb-16	0.36	0.22	0.336	0.220
19-Feb-16	0.34	0.21	0.336	0.219
20-Feb-16	0.33	0.17	0.335	0.217
21-Feb-16	0.31	0.19	0.334	0.216
22-Feb-16	0.32	0.20	0.333	0.216
23-Feb-16	0.31	0.19	0.331	0.215
24-Feb-16	0.29	0.18	0.329	0.214
25-Feb-16	0.30	0.21	0.329	0.214
26-Feb-16	0.33	0.24	0.329	0.215
27-Feb-16	0.33	0.21	0.328	0.214
28-Feb-16	0.31	0.20	0.328	0.213
29-Feb-16	0.30	0.19	0.327	0.212
1-Mar-16	0.31	0.20	0.327	0.212
2-Mar-16	0.36	0.22	0.328	0.213
3-Mar-16	0.35	0.23	0.330	0.213
4-Mar-16	0.35	0.21	0.331	0.214
5-Mar-16	0.35	0.21	0.332	0.213
6-Mar-16	0.36	0.20	0.333	0.212
7-Mar-16	0.36	0.19	0.334	0.211
8-Mar-16	0.31	0.19	0.333	0.209
9-Mar-16	0.29	0.19	0.332	0.209
10-Mar-16	0.26	0.18	0.330	0.207
11-Mar-16	0.28	0.20	0.328	0.206
12-Mar-16	0.27	0.20	0.325	0.205
13-Mar-16	0.26	0.19	0.322	0.204
14-Mar-16	0.24	0.18	0.318	0.202
15-Mar-16	0.25	0.17	0.315	0.200
16-Mar-16	0.26	0.18	0.312	0.199
17-Mar-16	0.26	0.20	0.310	0.198
18-Mar-16	0.28	0.23	0.307	0.199
19-Mar-16	0.30	0.21	0.305	0.198
20-Mar-16	0.31	0.22	0.305	0.199
21-Mar-16	0.33	0.23	0.305	0.201
22-Mar-16	0.32	0.21	0.305	0.201
23-Mar-16	0.26	0.20	0.303	0.201
24-Mar-16	0.25	0.18	0.301	0.201
25-Mar-16	0.26	0.20	0.300	0.201
26-Mar-16	0.30	0.21	0.300	0.201
27-Mar-16	0.27	0.18	0.298	0.199
28-Mar-16	0.26	0.20	0.296	0.199

29-Mar-16	0.29	0.22	0.295	0.200
30-Mar-16	0.29	0.22	0.295	0.201
31-Mar-16	0.25	0.18	0.293	0.200
1-Apr-16	0.24	0.18	0.288	0.199
2-Apr-16	0.26	0.21	0.285	0.198
3-Apr-16	0.35	0.23	0.285	0.199
4-Apr-16	0.30	0.20	0.284	0.199
5-Apr-16	0.35	0.23	0.283	0.200
6-Apr-16	0.33	0.20	0.282	0.200
7-Apr-16	0.27	0.19	0.281	0.200
8-Apr-16	0.33	0.23	0.282	0.202
9-Apr-16	0.35	0.23	0.285	0.203
10-Apr-16	0.37	0.23	0.288	0.204
11-Apr-16	0.30	0.18	0.289	0.204
12-Apr-16	0.29	0.20	0.291	0.204
13-Apr-16	0.33	0.21	0.293	0.205
14-Apr-16	0.30	0.19	0.295	0.206
15-Apr-16	0.28	0.19	0.296	0.206
16-Apr-16	0.27	0.18	0.296	0.206
17-Apr-16	0.27	0.18	0.296	0.204
18-Apr-16	0.27	0.18	0.294	0.203
19-Apr-16	0.26	0.18	0.293	0.201
20-Apr-16	0.27	0.18	0.290	0.200
21-Apr-16	0.25	0.16	0.288	0.198
22-Apr-16	0.22	0.16	0.287	0.197
23-Apr-16	0.24	0.17	0.287	0.197
24-Apr-16	0.24	0.18	0.286	0.196
25-Apr-16	0.23	0.18	0.284	0.195
26-Apr-16	0.23	0.17	0.282	0.195
27-Apr-16	0.24	0.17	0.282	0.194
28-Apr-16	0.23	0.18	0.280	0.193
29-Apr-16	0.14	0.11	0.275	0.189
30-Apr-16	0.13	0.09	0.271	0.186
1-May-16	0.23	0.10	0.271	0.183
2-May-16	0.23	0.10	0.270	0.180
3-May-16	0.23	0.10	0.266	0.176
4-May-16	0.23	0.10	0.264	0.172
5-May-16	0.26	0.10	0.261	0.168
6-May-16	0.31	0.10	0.260	0.165
7-May-16	0.26	0.10	0.260	0.162
8-May-16	0.23	0.11	0.256	0.158
9-May-16	0.22	0.11	0.252	0.154
10-May-16	0.20	0.10	0.246	0.150
11-May-16	0.21	0.09	0.244	0.147
12-May-16	0.20	0.09	0.240	0.143
13-May-16	0.18	0.10	0.235	0.139
14-May-16	0.16	0.10	0.231	0.136
15-May-16	0.19	0.11	0.228	0.134
16-May-16	0.19	0.10	0.225	0.131
17-May-16	0.21	0.10	0.223	0.129
18-May-16	0.07	0.18	0.216	0.129
19-May-16	0.00	0.24	0.208	0.130
20-May-16	0.00	0.23	0.199	0.132
21-May-16	0.00	0.22	0.191	0.134
22-May-16	0.00	0.23	0.183	0.136
23-May-16	0.00	0.22	0.175	0.138
24-May-16	0.00	0.23	0.167	0.139
25-May-16	0.00	0.22	0.160	0.141
26-May-16	0.00	0.21	0.152	0.142
27-May-16	0.00	0.20	0.144	0.143
28-May-16	0.00	0.20	0.137	0.143
29-May-16	0.00	0.21	0.132	0.147
30-May-16	0.00	0.22	0.128	0.151

31-May-16	0.00	0.22	0.121	0.155
1-Jun-16	0.00	0.21	0.113	0.159
2-Jun-16	0.00	0.20	0.106	0.162
3-Jun-16	0.00	0.21	0.098	0.166
4-Jun-16	0.00	0.21	0.089	0.169
5-Jun-16	0.01	0.21	0.079	0.172
6-Jun-16	0.00	0.20	0.071	0.176
7-Jun-16	0.00	0.24	0.063	0.180
8-Jun-16	0.00	0.24	0.056	0.184
9-Jun-16	0.00	0.24	0.050	0.189
10-Jun-16	0.00	0.22	0.043	0.193
11-Jun-16	0.00	0.21	0.036	0.197
12-Jun-16	0.00	0.25	0.030	0.202
13-Jun-16	0.00	0.26	0.025	0.208
14-Jun-16	0.01	0.26	0.019	0.212
15-Jun-16	0.08	0.20	0.016	0.216
16-Jun-16	0.02	0.18	0.009	0.218
17-Jun-16	0.12	0.23	0.011	0.220
18-Jun-16	0.17	0.23	0.017	0.220
19-Jun-16	0.17	0.24	0.022	0.220
20-Jun-16	0.15	0.23	0.027	0.221
21-Jun-16	0.16	0.22	0.033	0.221
22-Jun-16	0.16	0.24	0.038	0.221
23-Jun-16	0.15	0.22	0.043	0.221
24-Jun-16	0.14	0.13	0.047	0.218
25-Jun-16	0.14	0.11	0.052	0.215
26-Jun-16	0.14	0.09	0.056	0.211
27-Jun-16	0.19	0.11	0.062	0.208
28-Jun-16	0.18	0.12	0.068	0.205
29-Jun-16	0.17	0.12	0.074	0.202
30-Jun-16	0.18	0.12	0.080	0.199
1-Jul-16	0.17	0.12	0.085	0.195
2-Jul-16	0.19	0.11	0.091	0.192
3-Jul-16	0.18	0.11	0.097	0.189
4-Jul-16	0.17	0.10	0.103	0.185
5-Jul-16	0.17	0.10	0.108	0.182
6-Jul-16	0.17	0.10	0.113	0.178
7-Jul-16	0.16	0.10	0.119	0.174
8-Jul-16	0.17	0.09	0.124	0.169
9-Jul-16	0.18	0.10	0.130	0.164
10-Jul-16	0.19	0.10	0.136	0.160
11-Jul-16	0.17	0.10	0.142	0.157
12-Jul-16	0.17	0.10	0.147	0.152
13-Jul-16	0.17	0.10	0.152	0.147
14-Jul-16	0.17	0.10	0.158	0.141
15-Jul-16	0.17	0.10	0.161	0.138
16-Jul-16	0.17	0.10	0.166	0.135
17-Jul-16	0.18	0.10	0.168	0.131
18-Jul-16	0.18	0.10	0.168	0.127
19-Jul-16	0.19	0.11	0.168	0.123
20-Jul-16	0.18	0.11	0.169	0.118
21-Jul-16	0.17	0.10	0.170	0.115
22-Jul-16	0.17	0.10	0.170	0.110
23-Jul-16	0.17	0.09	0.170	0.105
24-Jul-16	0.17	0.10	0.171	0.104
25-Jul-16	0.16	0.10	0.172	0.104
26-Jul-16	0.16	0.10	0.173	0.104
27-Jul-16	0.16	0.10	0.172	0.104
28-Jul-16	0.16	0.10	0.171	0.103
29-Jul-16	0.17	0.10	0.171	0.103
30-Jul-16	0.17	0.10	0.171	0.102
31-Jul-16	0.21	0.12	0.172	0.102
1-Aug-16	0.22	0.13	0.173	0.103

2-Aug-16	0.21	0.12	0.174	0.103
3-Aug-16	0.19	0.11	0.175	0.104
4-Aug-16	0.20	0.12	0.176	0.105
5-Aug-16	0.22	0.13	0.177	0.106
6-Aug-16	0.22	0.13	0.179	0.107
7-Aug-16	0.20	0.12	0.181	0.108
8-Aug-16	0.17	0.10	0.180	0.108
9-Aug-16	0.17	0.11	0.180	0.108
10-Aug-16	0.15	0.11	0.179	0.108
11-Aug-16	0.15	0.10	0.179	0.108
12-Aug-16	0.15	0.10	0.178	0.108
13-Aug-16	0.14	0.10	0.177	0.108
14-Aug-16	0.15	0.10	0.177	0.108
15-Aug-16	0.15	0.09	0.176	0.107
16-Aug-16	0.16	0.09	0.176	0.107
17-Aug-16	0.15	0.08	0.175	0.106
18-Aug-16	0.14	0.09	0.173	0.105
19-Aug-16	0.14	0.08	0.172	0.105
20-Aug-16	0.14	0.08	0.171	0.104
21-Aug-16	0.15	0.09	0.171	0.104
22-Aug-16	0.16	0.09	0.170	0.103
23-Aug-16	0.16	0.10	0.170	0.103
24-Aug-16	0.17	0.09	0.171	0.103
25-Aug-16	0.16	0.09	0.170	0.103
26-Aug-16	0.16	0.09	0.170	0.102
27-Aug-16	0.16	0.09	0.170	0.102
28-Aug-16	0.16	0.09	0.170	0.101
29-Aug-16	0.16	0.09	0.170	0.101
30-Aug-16	0.16	0.09	0.168	0.100
31-Aug-16	0.16	0.09	0.166	0.099
1-Sep-16	0.16	0.09	0.165	0.098
2-Sep-16	0.14	0.09	0.163	0.097
3-Sep-16	0.14	0.09	0.161	0.095
4-Sep-16	0.14	0.09	0.158	0.094
5-Sep-16	0.14	0.08	0.156	0.092
6-Sep-16	0.14	0.08	0.154	0.091
7-Sep-16	0.12	0.07	0.152	0.090
8-Sep-16	0.12	0.08	0.150	0.089
9-Sep-16	0.11	0.08	0.149	0.088
10-Sep-16	0.13	0.08	0.148	0.087
11-Sep-16	0.14	0.08	0.148	0.087
12-Sep-16	0.14	0.09	0.148	0.087
13-Sep-16	0.14	0.08	0.147	0.086
14-Sep-16	0.13	0.08	0.147	0.086
15-Sep-16	0.14	0.08	0.146	0.086
16-Sep-16	0.15	0.04	0.146	0.084
17-Sep-16	0.17	0.00	0.147	0.082
18-Sep-16	0.16	0.00	0.148	0.079
19-Sep-16	0.19	0.00	0.149	0.076
20-Sep-16	0.21	0.01	0.151	0.074
21-Sep-16	0.21	0.00	0.152	0.071
22-Sep-16	0.17	0.00	0.153	0.068
23-Sep-16	0.17	0.00	0.153	0.065
24-Sep-16	0.18	0.00	0.153	0.062
25-Sep-16	0.20	0.00	0.155	0.059
26-Sep-16	0.20	0.00	0.156	0.056
27-Sep-16	0.21	0.00	0.158	0.053
28-Sep-16	0.19	0.00	0.159	0.051
29-Sep-16	0.19	0.00	0.160	0.048
30-Sep-16	0.19	0.00	0.161	0.045
1-Oct-16	0.19	0.00	0.161	0.042
2-Oct-16	0.28	0.00	0.166	0.039
3-Oct-16	0.32	0.00	0.172	0.036

4-Oct-16	0.29	0.00	0.177	0.033
5-Oct-16	0.29	0.03	0.182	0.032
6-Oct-16	0.30	0.01	0.187	0.029
7-Oct-16	0.30	0.00	0.193	0.027
8-Oct-16	0.31	0.00	0.199	0.024
9-Oct-16	0.37	0.00	0.208	0.022
10-Oct-16	0.38	0.00	0.217	0.020
11-Oct-16	0.34	0.00	0.223	0.017
12-Oct-16	0.32	0.00	0.230	0.014
13-Oct-16	0.32	0.00	0.236	0.011
14-Oct-16	0.33	0.00	0.242	0.009
15-Oct-16	0.32	0.00	0.248	0.006
16-Oct-16	0.33	0.00	0.254	0.005
17-Oct-16	0.31	0.00	0.259	0.005
18-Oct-16	0.30	0.00	0.264	0.005
19-Oct-16	0.31	0.00	0.268	0.005
20-Oct-16	0.30	0.00	0.271	0.005
21-Oct-16	0.28	0.01	0.273	0.005
22-Oct-16	0.33	0.00	0.279	0.005
23-Oct-16	0.32	0.00	0.284	0.005
24-Oct-16	0.33	0.00	0.289	0.005
25-Oct-16	0.36	0.00	0.294	0.005
26-Oct-16	0.35	0.02	0.299	0.005
27-Oct-16	0.31	0.10	0.303	0.009
28-Oct-16	0.28	0.18	0.305	0.014
29-Oct-16	0.29	0.19	0.309	0.021
30-Oct-16	0.28	0.16	0.312	0.026
31-Oct-16	0.30	0.18	0.316	0.032
1-Nov-16	0.27	0.18	0.315	0.037
2-Nov-16	0.31	0.18	0.315	0.043
3-Nov-16	0.30	0.18	0.316	0.049
4-Nov-16	0.34	0.20	0.317	0.055
5-Nov-16	0.35	0.19	0.318	0.061
6-Nov-16	0.35	0.19	0.320	0.067
7-Nov-16	0.36	0.18	0.322	0.073
8-Nov-16	0.34	0.17	0.321	0.079
9-Nov-16	0.30	0.18	0.318	0.084
10-Nov-16	0.35	0.17	0.318	0.090
11-Nov-16	0.36	0.14	0.320	0.094
12-Nov-16	0.37	0.16	0.321	0.100
13-Nov-16	0.37	0.17	0.322	0.105
14-Nov-16	0.34	0.16	0.323	0.111
15-Nov-16	0.33	0.15	0.323	0.116
16-Nov-16	0.29	0.15	0.322	0.120
17-Nov-16	0.33	0.15	0.323	0.125
18-Nov-16	0.32	0.14	0.324	0.130
19-Nov-16	0.32	0.17	0.325	0.135
20-Nov-16	0.33	0.18	0.326	0.141
21-Nov-16	0.33	0.17	0.326	0.146
22-Nov-16	0.31	0.16	0.326	0.151
23-Nov-16	0.36	0.19	0.327	0.158
24-Nov-16	0.39	0.20	0.328	0.164
25-Nov-16	0.37	0.22	0.329	0.171
26-Nov-16	0.38	0.24	0.331	0.175
27-Nov-16	0.35	0.22	0.333	0.177
28-Nov-16	0.31	0.16	0.334	0.176
29-Nov-16	0.30	0.13	0.334	0.175
30-Nov-16	0.27	0.14	0.333	0.174
1-Dec-16	0.30	0.16	0.334	0.173
2-Dec-16	0.30	0.16	0.334	0.173
3-Dec-16	0.31	0.15	0.334	0.172
4-Dec-16	0.31	0.15	0.333	0.170
5-Dec-16	0.31	0.14	0.332	0.169

6-Dec-16	0.30	0.15	0.331	0.168
7-Dec-16	0.31	0.15	0.329	0.167
8-Dec-16	0.31	0.17	0.328	0.167
9-Dec-16	0.32	0.18	0.329	0.166
10-Dec-16	0.32	0.18	0.328	0.167
11-Dec-16	0.33	0.17	0.327	0.168
12-Dec-16	0.31	0.16	0.325	0.168
13-Dec-16	0.31	0.17	0.323	0.168
14-Dec-16	0.31	0.18	0.322	0.169
15-Dec-16	0.32	0.20	0.322	0.170
16-Dec-16	0.32	0.19	0.323	0.172
17-Dec-16	0.29	0.16	0.321	0.172
18-Dec-16	0.30	0.17	0.320	0.173
19-Dec-16	0.33	0.20	0.321	0.174
20-Dec-16	0.32	0.20	0.320	0.175
21-Dec-16	0.30	0.20	0.320	0.176
22-Dec-16	0.31	0.18	0.320	0.177
23-Dec-16	0.32	0.19	0.318	0.177
24-Dec-16	0.30	0.18	0.315	0.176
25-Dec-16	0.31	0.19	0.313	0.175
26-Dec-16	0.29	0.17	0.310	0.173
27-Dec-16	0.30	0.19	0.308	0.172
28-Dec-16	0.32	0.20	0.309	0.173
29-Dec-16	0.31	0.19	0.309	0.175
30-Dec-16	0.32	0.20	0.311	0.177
31-Dec-16	0.31	0.19	0.311	0.178
1-Jan-17	0.34	0.17	0.312	0.178
2-Jan-17	0.33	0.16	0.313	0.178
3-Jan-17	0.29	0.14	0.312	0.178
4-Jan-17	0.31	0.18	0.312	0.179
5-Jan-17	0.35	0.20	0.314	0.181
6-Jan-17	0.34	0.19	0.315	0.182
7-Jan-17	0.34	0.20	0.316	0.183
8-Jan-17	0.35	0.19	0.317	0.183
9-Jan-17	0.34	0.19	0.317	0.184
10-Jan-17	0.33	0.16	0.317	0.183
11-Jan-17	0.32	0.16	0.318	0.183
12-Jan-17	0.28	0.15	0.317	0.182
13-Jan-17	0.33	0.20	0.317	0.183
14-Jan-17	0.34	0.20	0.318	0.183
15-Jan-17	0.34	0.18	0.319	0.182
16-Jan-17	0.32	0.18	0.320	0.183
17-Jan-17	0.27	0.16	0.319	0.183
18-Jan-17	0.31	0.16	0.318	0.182
19-Jan-17	0.32	0.21	0.318	0.182
20-Jan-17	0.30	0.17	0.317	0.181
21-Jan-17	0.30	0.15	0.317	0.180
22-Jan-17	0.29	0.15	0.316	0.179
23-Jan-17	0.29	0.18	0.316	0.179
24-Jan-17	0.30	0.16	0.316	0.178
25-Jan-17	0.30	0.15	0.316	0.177
26-Jan-17	0.31	0.19	0.316	0.177
27-Jan-17	0.34	0.22	0.317	0.178
28-Jan-17	0.36	0.22	0.318	0.179
29-Jan-17	0.36	0.19	0.320	0.179
30-Jan-17	0.36	0.18	0.321	0.179
31-Jan-17	0.36	0.17	0.322	0.179
1-Feb-17	0.35	0.17	0.323	0.179
2-Feb-17	0.37	0.18	0.325	0.180
3-Feb-17	0.38	0.20	0.327	0.181
4-Feb-17	0.38	0.20	0.328	0.181
5-Feb-17	0.38	0.17	0.330	0.180
6-Feb-17	0.40	0.20	0.332	0.180

7-Feb-17	0.34	0.18	0.331	0.180
8-Feb-17	0.31	0.17	0.330	0.179
9-Feb-17	0.34	0.19	0.331	0.180
10-Feb-17	0.36	0.20	0.332	0.182
11-Feb-17	0.35	0.16	0.334	0.182
12-Feb-17	0.33	0.15	0.334	0.180
13-Feb-17	0.37	0.17	0.335	0.179
14-Feb-17	0.43	0.21	0.338	0.180
15-Feb-17	0.33	0.17	0.339	0.180
16-Feb-17	0.37	0.19	0.342	0.181
17-Feb-17	0.35	0.18	0.343	0.181
18-Feb-17	0.33	0.16	0.344	0.180
19-Feb-17	0.31	0.15	0.344	0.179
20-Feb-17	0.33	0.16	0.345	0.179
21-Feb-17	0.37	0.17	0.348	0.180
22-Feb-17	0.30	0.15	0.348	0.179
23-Feb-17	0.28	0.15	0.348	0.179
24-Feb-17	0.28	0.15	0.347	0.179
25-Feb-17	0.29	0.18	0.346	0.178
26-Feb-17	0.37	0.19	0.347	0.177
27-Feb-17	0.38	0.17	0.348	0.176
28-Feb-17	0.40	0.21	0.350	0.176
1-Mar-17	0.36	0.16	0.350	0.175
2-Mar-17	0.34	0.19	0.349	0.176
3-Mar-17	0.40	0.18	0.351	0.177
4-Mar-17	0.41	0.18	0.353	0.177
5-Mar-17	0.43	0.19	0.354	0.176
6-Mar-17	0.41	0.19	0.355	0.176
7-Mar-17	0.34	0.16	0.354	0.175
8-Mar-17	0.34	0.19	0.352	0.175
9-Mar-17	0.30	0.20	0.351	0.176
10-Mar-17	0.29	0.22	0.350	0.178
11-Mar-17	0.30	0.21	0.349	0.178
12-Mar-17	0.30	0.19	0.347	0.178
13-Mar-17	0.30	0.19	0.346	0.179
14-Mar-17	0.29	0.21	0.344	0.181
15-Mar-17	0.31	0.22	0.342	0.183
16-Mar-17	0.31	0.19	0.338	0.182
17-Mar-17	0.33	0.20	0.338	0.183
18-Mar-17	0.35	0.18	0.337	0.183
19-Mar-17	0.37	0.18	0.338	0.183
20-Mar-17	0.42	0.19	0.341	0.184
21-Mar-17	0.39	0.18	0.343	0.185
22-Mar-17	0.35	0.20	0.344	0.186
23-Mar-17	0.38	0.19	0.344	0.187
24-Mar-17	0.32	0.16	0.345	0.187
25-Mar-17	0.29	0.15	0.345	0.187
26-Mar-17	0.31	0.17	0.346	0.188
27-Mar-17	0.41	0.05	0.350	0.184
28-Mar-17	0.39	0.00	0.351	0.177
29-Mar-17	0.39	0.00	0.351	0.172
30-Mar-17	0.44	0.00	0.352	0.165
31-Mar-17	0.39	0.00	0.353	0.159
1-Apr-17	0.42	0.00	0.356	0.153
2-Apr-17	0.45	0.00	0.358	0.147
3-Apr-17	0.42	0.00	0.358	0.141
4-Apr-17	0.40	0.00	0.357	0.134
5-Apr-17	0.37	0.00	0.356	0.128
6-Apr-17	0.35	0.00	0.356	0.123
7-Apr-17	0.32	0.00	0.355	0.116
8-Apr-17	0.44	0.00	0.360	0.110
9-Apr-17	0.48	0.00	0.366	0.102
10-Apr-17	0.32	0.00	0.367	0.095

11-Apr-17	0.28	0.00	0.366	0.089
12-Apr-17	0.34	0.00	0.367	0.083
13-Apr-17	0.39	0.00	0.370	0.076
14-Apr-17	0.40	0.00	0.374	0.068
15-Apr-17	0.37	0.00	0.376	0.062
16-Apr-17	0.36	0.00	0.377	0.056
17-Apr-17	0.43	0.00	0.379	0.050
18-Apr-17	0.44	0.00	0.382	0.044
19-Apr-17	0.38	0.00	0.380	0.037
20-Apr-17	0.35	0.00	0.379	0.031
21-Apr-17	0.37	0.00	0.380	0.024
22-Apr-17	0.40	0.00	0.380	0.018
23-Apr-17	0.43	0.00	0.384	0.013
24-Apr-17	0.43	0.00	0.388	0.007
25-Apr-17	0.41	0.00	0.392	0.002
26-Apr-17	0.37	0.00	0.390	0.000
27-Apr-17	0.37	0.00	0.390	0.000
28-Apr-17	0.39	0.00	0.389	0.000
29-Apr-17	0.37	0.00	0.387	0.000
30-Apr-17	0.33	0.00	0.385	0.000
1-May-17	0.32	0.00	0.382	0.000
2-May-17	0.39	0.00	0.380	0.000
3-May-17	0.44	0.00	0.380	0.000
4-May-17	0.42	0.00	0.381	0.000
5-May-17	0.39	0.00	0.382	0.000
6-May-17	0.40	0.00	0.383	0.000
7-May-17	0.42	0.02	0.387	0.001
8-May-17	0.34	0.12	0.383	0.005
9-May-17	0.20	0.14	0.374	0.009
10-May-17	0.19	0.09	0.370	0.012
11-May-17	0.17	0.09	0.366	0.015
12-May-17	0.16	0.09	0.360	0.018
13-May-17	0.15	0.09	0.352	0.021
14-May-17	0.16	0.09	0.344	0.024
15-May-17	0.16	0.09	0.337	0.027
16-May-17	0.15	0.08	0.330	0.030
17-May-17	0.15	0.08	0.321	0.032
18-May-17	0.15	0.08	0.311	0.035
19-May-17	0.14	0.08	0.304	0.038
20-May-17	0.15	0.08	0.297	0.040
21-May-17	0.15	0.08	0.289	0.043
22-May-17	0.18	0.08	0.282	0.046
23-May-17	0.16	0.08	0.273	0.048
24-May-17	0.13	0.08	0.263	0.051
25-May-17	0.13	0.08	0.254	0.054
26-May-17	0.13	0.08	0.246	0.056
27-May-17	0.14	0.08	0.238	0.059
28-May-17	0.14	0.08	0.230	0.062
29-May-17	0.18	0.08	0.224	0.064
30-May-17	0.20	0.08	0.219	0.067
31-May-17	0.14	0.08	0.213	0.070
1-Jun-17	0.14	0.08	0.205	0.072
2-Jun-17	0.15	0.08	0.195	0.075
3-Jun-17	0.15	0.08	0.186	0.078
4-Jun-17	0.18	0.08	0.179	0.081
5-Jun-17	0.20	0.08	0.172	0.083
6-Jun-17	0.14	0.08	0.163	0.085
7-Jun-17	0.14	0.08	0.156	0.084
8-Jun-17	0.14	0.08	0.154	0.082
9-Jun-17	0.14	0.08	0.152	0.082
10-Jun-17	0.14	0.08	0.151	0.081
11-Jun-17	0.14	0.08	0.151	0.081
12-Jun-17	0.19	0.08	0.152	0.081

13-Jun-17	0.18	0.08	0.153	0.080
14-Jun-17	0.12	0.08	0.151	0.080
15-Jun-17	0.12	0.08	0.150	0.080
16-Jun-17	0.12	0.08	0.149	0.080
17-Jun-17	0.12	0.08	0.149	0.080
18-Jun-17	0.13	0.08	0.148	0.080
19-Jun-17	0.21	0.08	0.150	0.080
20-Jun-17	0.24	0.09	0.153	0.080
21-Jun-17	0.13	0.08	0.152	0.080
22-Jun-17	0.14	0.08	0.151	0.080
23-Jun-17	0.13	0.07	0.151	0.080
24-Jun-17	0.13	0.08	0.151	0.080
25-Jun-17	0.14	0.08	0.151	0.080
26-Jun-17	0.15	0.08	0.152	0.080
27-Jun-17	0.20	0.09	0.154	0.080
28-Jun-17	0.14	0.09	0.153	0.081
29-Jun-17	0.14	0.08	0.151	0.080
30-Jun-17	0.14	0.07	0.151	0.080
1-Jul-17	0.13	0.08	0.150	0.080
2-Jul-17	0.15	0.08	0.150	0.080
3-Jul-17	0.21	0.08	0.152	0.080
4-Jul-17	0.13	0.07	0.151	0.080
5-Jul-17	0.12	0.07	0.148	0.080
6-Jul-17	0.13	0.07	0.148	0.080
7-Jul-17	0.13	0.07	0.148	0.079
8-Jul-17	0.13	0.08	0.147	0.079
9-Jul-17	0.15	0.08	0.148	0.079
10-Jul-17	0.16	0.08	0.148	0.079
11-Jul-17	0.13	0.08	0.148	0.079
12-Jul-17	0.12	0.07	0.146	0.079
13-Jul-17	0.12	0.07	0.144	0.079
14-Jul-17	0.11	0.07	0.143	0.079
15-Jul-17	0.12	0.07	0.143	0.079
16-Jul-17	0.13	0.08	0.144	0.078
17-Jul-17	0.13	0.07	0.144	0.078
18-Jul-17	0.14	0.08	0.144	0.078
19-Jul-17	0.13	0.07	0.142	0.078
20-Jul-17	0.13	0.07	0.138	0.077
21-Jul-17	0.12	0.07	0.137	0.077
22-Jul-17	0.12	0.07	0.137	0.077
23-Jul-17	0.12	0.07	0.137	0.077
24-Jul-17	0.13	0.08	0.136	0.077
25-Jul-17	0.17	0.08	0.138	0.077
26-Jul-17	0.13	0.08	0.137	0.077
27-Jul-17	0.13	0.07	0.135	0.076
28-Jul-17	0.12	0.07	0.134	0.076
29-Jul-17	0.14	0.08	0.134	0.076
30-Jul-17	0.14	0.08	0.134	0.076
31-Jul-17	0.15	0.08	0.135	0.076
1-Aug-17	0.14	0.08	0.135	0.076
2-Aug-17	0.14	0.07	0.133	0.075
3-Aug-17	0.16	0.03	0.134	0.074
4-Aug-17	0.17	0.00	0.135	0.072
5-Aug-17	0.18	0.00	0.137	0.069
6-Aug-17	0.18	0.00	0.138	0.067
7-Aug-17	0.16	0.00	0.139	0.064
8-Aug-17	0.16	0.00	0.140	0.061
9-Aug-17	0.16	0.00	0.140	0.059
10-Aug-17	0.16	0.02	0.141	0.057
11-Aug-17	0.16	0.14	0.142	0.059
12-Aug-17	0.13	0.11	0.142	0.060
13-Aug-17	0.12	0.09	0.143	0.061
14-Aug-17	0.12	0.09	0.143	0.061

15-Aug-17	0.13	0.11	0.143	0.062
16-Aug-17	0.12	0.08	0.143	0.063
17-Aug-17	0.12	0.08	0.142	0.063
18-Aug-17	0.12	0.08	0.142	0.063
19-Aug-17	0.14	0.08	0.142	0.063
20-Aug-17	0.14	0.08	0.142	0.064
21-Aug-17	0.13	0.08	0.143	0.064
22-Aug-17	0.13	0.08	0.143	0.064
23-Aug-17	0.17	0.08	0.145	0.064
24-Aug-17	0.16	0.09	0.144	0.065
25-Aug-17	0.14	0.09	0.144	0.065
26-Aug-17	0.15	0.09	0.145	0.066
27-Aug-17	0.14	0.09	0.146	0.066
28-Aug-17	0.20	0.09	0.148	0.067
29-Aug-17	0.15	0.09	0.148	0.067
30-Aug-17	0.13	0.09	0.147	0.068
31-Aug-17	0.13	0.09	0.147	0.068
1-Sep-17	0.13	0.09	0.147	0.069
2-Sep-17	0.13	0.09	0.146	0.071
3-Sep-17	0.13	0.09	0.144	0.074
4-Sep-17	0.18	0.09	0.144	0.077
5-Sep-17	0.19	0.12	0.145	0.080
6-Sep-17	0.21	0.10	0.147	0.084
7-Sep-17	0.23	0.09	0.149	0.087
8-Sep-17	0.23	0.09	0.151	0.090
9-Sep-17	0.24	0.10	0.154	0.092
10-Sep-17	0.25	0.10	0.157	0.091
11-Sep-17	0.26	0.13	0.161	0.092
12-Sep-17	0.23	0.09	0.165	0.092
13-Sep-17	0.20	0.09	0.167	0.092
14-Sep-17	0.21	0.09	0.170	0.091
15-Sep-17	0.21	0.09	0.173	0.092
16-Sep-17	0.19	0.09	0.175	0.092
17-Sep-17	0.19	0.09	0.177	0.092
18-Sep-17	0.07	0.21	0.175	0.096
19-Sep-17	0.00	0.26	0.171	0.102
20-Sep-17	0.00	0.26	0.166	0.108
21-Sep-17	0.00	0.27	0.162	0.115
22-Sep-17	0.00	0.28	0.157	0.121
23-Sep-17	0.00	0.29	0.151	0.128
24-Sep-17	0.00	0.29	0.147	0.135
25-Sep-17	0.00	0.28	0.142	0.141
26-Sep-17	0.00	0.26	0.137	0.147
27-Sep-17	0.00	0.26	0.131	0.152
28-Sep-17	0.00	0.30	0.126	0.159
29-Sep-17	0.01	0.32	0.122	0.167
30-Sep-17	0.00	0.33	0.118	0.175
1-Oct-17	0.00	0.34	0.114	0.183
2-Oct-17	0.00	0.33	0.109	0.191
3-Oct-17	0.01	0.30	0.105	0.198
4-Oct-17	0.00	0.29	0.099	0.205
5-Oct-17	0.00	0.27	0.093	0.210
6-Oct-17	0.00	0.25	0.086	0.215
7-Oct-17	0.00	0.27	0.079	0.221
8-Oct-17	0.00	0.26	0.071	0.227
9-Oct-17	0.00	0.26	0.063	0.232
10-Oct-17	0.00	0.27	0.055	0.238
11-Oct-17	0.00	0.25	0.047	0.242
12-Oct-17	0.00	0.25	0.039	0.247
13-Oct-17	0.00	0.21	0.033	0.251
14-Oct-17	0.00	0.19	0.026	0.254
15-Oct-17	0.00	0.24	0.019	0.259
16-Oct-17	0.00	0.26	0.013	0.265

17-Oct-17	0.00	0.26	0.007	0.271
18-Oct-17	0.00	0.25	0.004	0.272
19-Oct-17	0.00	0.24	0.004	0.271
20-Oct-17	0.01	0.24	0.005	0.271
21-Oct-17	0.03	0.25	0.005	0.270
22-Oct-17	0.01	0.24	0.005	0.269
23-Oct-17	0.00	0.23	0.005	0.267
24-Oct-17	0.00	0.24	0.005	0.265
25-Oct-17	0.00	0.25	0.005	0.264
26-Oct-17	0.01	0.23	0.005	0.263
27-Oct-17	0.15	0.20	0.010	0.261
28-Oct-17	0.23	0.18	0.018	0.257
29-Oct-17	0.20	0.22	0.024	0.253
30-Oct-17	0.26	0.20	0.033	0.249
31-Oct-17	0.32	0.20	0.043	0.245
1-Nov-17	0.31	0.22	0.053	0.241
2-Nov-17	0.26	0.16	0.062	0.236
3-Nov-17	0.24	0.16	0.070	0.232
4-Nov-17	0.28	0.16	0.079	0.228
5-Nov-17	0.28	0.21	0.088	0.227
6-Nov-17	0.28	0.20	0.097	0.224
7-Nov-17	0.31	0.20	0.107	0.222
8-Nov-17	0.30	0.19	0.117	0.220
9-Nov-17	0.31	0.18	0.127	0.217
10-Nov-17	0.32	0.23	0.138	0.216
11-Nov-17	0.32	0.24	0.148	0.216
12-Nov-17	0.31	0.20	0.159	0.216
13-Nov-17	0.33	0.17	0.169	0.215
14-Nov-17	0.34	0.18	0.181	0.213
15-Nov-17	0.33	0.19	0.191	0.211
16-Nov-17	0.31	0.16	0.202	0.208
17-Nov-17	0.32	0.17	0.213	0.205
18-Nov-17	0.31	0.17	0.223	0.203
19-Nov-17	0.33	0.17	0.234	0.200
20-Nov-17	0.36	0.20	0.245	0.199
21-Nov-17	0.35	0.16	0.256	0.196
22-Nov-17	0.34	0.18	0.267	0.194
23-Nov-17	0.35	0.19	0.279	0.193
24-Nov-17	0.36	0.18	0.291	0.190
25-Nov-17	0.35	0.16	0.302	0.188
26-Nov-17	0.36	0.17	0.309	0.187
27-Nov-17	0.37	0.17	0.314	0.186
28-Nov-17	0.35	0.16	0.319	0.185
29-Nov-17	0.34	0.16	0.322	0.183
30-Nov-17	0.33	0.18	0.322	0.182
1-Dec-17	0.33	0.17	0.323	0.181
2-Dec-17	0.32	0.23	0.325	0.183
3-Dec-17	0.34	0.19	0.328	0.184
4-Dec-17	0.34	0.18	0.330	0.185
5-Dec-17	0.29	0.18	0.331	0.184
6-Dec-17	0.33	0.21	0.332	0.184
7-Dec-17	0.32	0.18	0.333	0.184
8-Dec-17	0.34	0.22	0.334	0.185
9-Dec-17	0.35	0.19	0.336	0.185
10-Dec-17	0.35	0.18	0.336	0.183
11-Dec-17	0.35	0.18	0.338	0.181
12-Dec-17	0.34	0.20	0.338	0.181
13-Dec-17	0.34	0.21	0.339	0.183
14-Dec-17	0.35	0.20	0.339	0.183
15-Dec-17	0.34	0.20	0.339	0.183
16-Dec-17	0.38	0.20	0.341	0.185
17-Dec-17	0.36	0.16	0.342	0.184
18-Dec-17	0.35	0.16	0.344	0.184

19-Dec-17	0.33	0.18	0.344	0.184
20-Dec-17	0.35	0.21	0.344	0.185
21-Dec-17	0.37	0.22	0.344	0.186
22-Dec-17	0.34	0.16	0.344	0.186
23-Dec-17	0.31	0.18	0.343	0.186
24-Dec-17	0.35	0.22	0.343	0.187
25-Dec-17	0.42	0.26	0.345	0.190
26-Dec-17	0.39	0.25	0.346	0.193
27-Dec-17	0.38	0.22	0.346	0.195
28-Dec-17	0.36	0.24	0.347	0.197
29-Dec-17	0.38	0.24	0.348	0.200
30-Dec-17	0.38	0.22	0.350	0.201
31-Dec-17	0.39	0.22	0.352	0.203
1-Jan-18	0.40	0.20	0.354	0.202
2-Jan-18	0.39	0.19	0.356	0.201
3-Jan-18	0.36	0.19	0.357	0.202
4-Jan-18	0.36	0.20	0.359	0.203
5-Jan-18	0.37	0.23	0.360	0.203
6-Jan-18	0.37	0.20	0.362	0.204
7-Jan-18	0.37	0.19	0.363	0.203
8-Jan-18	0.35	0.17	0.363	0.203
9-Jan-18	0.37	0.17	0.363	0.202
10-Jan-18	0.36	0.18	0.363	0.202
11-Jan-18	0.32	0.17	0.363	0.201
12-Jan-18	0.31	0.18	0.362	0.200
13-Jan-18	0.36	0.25	0.362	0.202
14-Jan-18	0.38	0.19	0.364	0.201
15-Jan-18	0.37	0.17	0.364	0.200
16-Jan-18	0.36	0.19	0.364	0.201
17-Jan-18	0.36	0.18	0.365	0.202
18-Jan-18	0.37	0.19	0.366	0.202
19-Jan-18	0.35	0.19	0.366	0.202
20-Jan-18	0.33	0.22	0.364	0.202
21-Jan-18	0.26	0.19	0.362	0.203
22-Jan-18	0.21	0.19	0.358	0.203
23-Jan-18	0.22	0.24	0.354	0.204
24-Jan-18	0.23	0.29	0.348	0.205
25-Jan-18	0.24	0.30	0.342	0.206
26-Jan-18	0.32	0.23	0.340	0.207
27-Jan-18	0.36	0.19	0.340	0.205
28-Jan-18	0.38	0.18	0.340	0.203
29-Jan-18	0.37	0.21	0.340	0.203
30-Jan-18	0.39	0.22	0.340	0.203
31-Jan-18	0.39	0.22	0.340	0.203
1-Feb-18	0.37	0.19	0.339	0.203
2-Feb-18	0.37	0.21	0.339	0.204
3-Feb-18	0.38	0.17	0.340	0.203
4-Feb-18	0.34	0.15	0.339	0.201
5-Feb-18	0.35	0.20	0.339	0.201
6-Feb-18	0.37	0.19	0.339	0.201
7-Feb-18	0.33	0.19	0.338	0.201
8-Feb-18	0.35	0.18	0.338	0.202
9-Feb-18	0.35	0.16	0.337	0.201
10-Feb-18	0.32	0.15	0.337	0.200
11-Feb-18	0.33	0.15	0.338	0.199
12-Feb-18	0.36	0.19	0.338	0.198
13-Feb-18	0.39	0.19	0.338	0.198
14-Feb-18	0.35	0.14	0.337	0.197
15-Feb-18	0.30	0.14	0.335	0.195
16-Feb-18	0.31	0.18	0.333	0.195
17-Feb-18	0.33	0.19	0.332	0.195
18-Feb-18	0.32	0.17	0.331	0.194
19-Feb-18	0.32	0.15	0.331	0.192

20-Feb-18	0.30	0.14	0.332	0.190
21-Feb-18	0.24	0.14	0.333	0.189
22-Feb-18	0.26	0.19	0.334	0.187
23-Feb-18	0.26	0.15	0.335	0.182
24-Feb-18	0.26	0.16	0.336	0.178
25-Feb-18	0.27	0.16	0.334	0.176
26-Feb-18	0.28	0.20	0.331	0.176
27-Feb-18	0.32	0.19	0.330	0.176
28-Feb-18	0.32	0.16	0.328	0.175
1-Mar-18	0.31	0.15	0.326	0.172
2-Mar-18	0.32	0.22	0.323	0.172
3-Mar-18	0.34	0.21	0.322	0.173
4-Mar-18	0.33	0.18	0.320	0.172
5-Mar-18	0.34	0.19	0.319	0.173
6-Mar-18	0.32	0.17	0.319	0.173
7-Mar-18	0.32	0.18	0.318	0.172
8-Mar-18	0.35	0.21	0.317	0.173
9-Mar-18	0.35	0.19	0.317	0.173
10-Mar-18	0.35	0.20	0.318	0.174
11-Mar-18	0.37	0.18	0.318	0.174
12-Mar-18	0.37	0.24	0.320	0.177
13-Mar-18	0.35	0.20	0.321	0.179
14-Mar-18	0.34	0.21	0.320	0.179
15-Mar-18	0.35	0.20	0.319	0.180
16-Mar-18	0.35	0.20	0.319	0.182
17-Mar-18	0.35	0.21	0.320	0.184
18-Mar-18	0.35	0.19	0.322	0.184
19-Mar-18	0.37	0.19	0.323	0.184
20-Mar-18	0.35	0.17	0.324	0.184
21-Mar-18	0.33	0.19	0.325	0.185
22-Mar-18	0.35	0.19	0.327	0.187
23-Mar-18	0.37	0.20	0.331	0.189
24-Mar-18	0.38	0.22	0.335	0.190
25-Mar-18	0.38	0.22	0.339	0.192
26-Mar-18	0.36	0.18	0.342	0.193
27-Mar-18	0.33	0.17	0.344	0.193
28-Mar-18	0.30	0.16	0.345	0.192
29-Mar-18	0.28	0.15	0.343	0.190
30-Mar-18	0.32	0.18	0.343	0.191
31-Mar-18	0.35	0.19	0.345	0.192
1-Apr-18	0.32	0.18	0.345	0.191
2-Apr-18	0.35	0.07	0.345	0.186
3-Apr-18	0.32	0.00	0.345	0.180
4-Apr-18	0.33	0.00	0.344	0.174
5-Apr-18	0.33	0.00	0.345	0.168
6-Apr-18	0.33	0.01	0.345	0.163
7-Apr-18	0.33	0.00	0.344	0.156
8-Apr-18	0.32	0.00	0.343	0.149
9-Apr-18	0.34	0.00	0.343	0.143
10-Apr-18	0.35	0.00	0.342	0.137
11-Apr-18	0.35	0.00	0.342	0.129
12-Apr-18	0.34	0.00	0.341	0.123
13-Apr-18	0.34	0.01	0.341	0.116
14-Apr-18	0.32	0.01	0.340	0.110
15-Apr-18	0.31	0.00	0.339	0.103
16-Apr-18	0.34	0.00	0.338	0.096
17-Apr-18	0.36	0.00	0.339	0.090
18-Apr-18	0.37	0.00	0.339	0.084
19-Apr-18	0.35	0.00	0.338	0.079
20-Apr-18	0.39	0.00	0.340	0.072
21-Apr-18	0.38	0.01	0.341	0.066
22-Apr-18	0.38	0.00	0.341	0.060
23-Apr-18	0.34	0.01	0.340	0.053

24-Apr-18	0.34	0.01	0.339	0.046
25-Apr-18	0.32	0.00	0.338	0.040
26-Apr-18	0.32	0.01	0.337	0.035
27-Apr-18	0.31	0.00	0.338	0.030
28-Apr-18	0.33	0.00	0.339	0.025
29-Apr-18	0.37	0.00	0.341	0.019
30-Apr-18	0.32	0.00	0.340	0.013
1-May-18	0.25	0.00	0.337	0.007
2-May-18	0.23	0.00	0.333	0.005
3-May-18	0.20	0.00	0.330	0.005
4-May-18	0.21	0.00	0.326	0.005
5-May-18	0.22	0.00	0.322	0.005
6-May-18	0.26	0.00	0.320	0.005
7-May-18	0.23	0.00	0.316	0.005
8-May-18	0.31	0.00	0.316	0.005
9-May-18	0.30	0.00	0.315	0.005
10-May-18	0.31	0.00	0.313	0.005
11-May-18	0.32	0.00	0.312	0.005
12-May-18	0.32	0.01	0.312	0.005
13-May-18	0.32	0.00	0.311	0.005
14-May-18	0.30	0.00	0.310	0.004
15-May-18	0.30	0.00	0.310	0.004
16-May-18	0.29	0.00	0.308	0.004
17-May-18	0.28	0.00	0.306	0.004
18-May-18	0.28	0.00	0.303	0.004
19-May-18	0.27	0.00	0.300	0.004
20-May-18	0.27	0.00	0.296	0.004
21-May-18	0.27	0.01	0.292	0.005
22-May-18	0.23	0.11	0.288	0.008
23-May-18	0.22	0.19	0.284	0.014
24-May-18	0.20	0.15	0.279	0.019
25-May-18	0.22	0.13	0.276	0.023
26-May-18	0.22	0.12	0.272	0.027
27-May-18	0.22	0.12	0.269	0.030
28-May-18	0.22	0.12	0.266	0.034
29-May-18	0.18	0.11	0.260	0.038
30-May-18	0.18	0.11	0.255	0.041
31-May-18	0.19	0.10	0.253	0.045
1-Jun-18	0.20	0.11	0.252	0.048
2-Jun-18	0.19	0.12	0.251	0.052
3-Jun-18	0.19	0.11	0.250	0.056
4-Jun-18	0.22	0.11	0.251	0.059
5-Jun-18	0.23	0.12	0.250	0.063
6-Jun-18	0.19	0.13	0.248	0.067
7-Jun-18	0.20	0.12	0.245	0.071
8-Jun-18	0.18	0.13	0.241	0.076
9-Jun-18	0.19	0.13	0.237	0.080
10-Jun-18	0.21	0.13	0.233	0.084
11-Jun-18	0.22	0.15	0.230	0.089
12-Jun-18	0.22	0.13	0.227	0.093
13-Jun-18	0.21	0.12	0.224	0.097
14-Jun-18	0.22	0.13	0.221	0.101
15-Jun-18	0.17	0.12	0.217	0.105
16-Jun-18	0.15	0.11	0.213	0.108
17-Jun-18	0.15	0.10	0.208	0.112
18-Jun-18	0.19	0.10	0.205	0.115
19-Jun-18	0.20	0.12	0.203	0.119
20-Jun-18	0.18	0.13	0.200	0.123
21-Jun-18	0.14	0.22	0.197	0.126
22-Jun-18	0.24	0.16	0.197	0.126
23-Jun-18	0.20	0.13	0.197	0.125
24-Jun-18	0.21	0.13	0.197	0.125
25-Jun-18	0.15	0.20	0.194	0.128

26-Jun-18	0.20	0.14	0.194	0.128
27-Jun-18	0.20	0.13	0.193	0.129
28-Jun-18	0.20	0.13	0.194	0.129
29-Jun-18	0.18	0.13	0.194	0.129
30-Jun-18	0.18	0.13	0.193	0.130
1-Jul-18	0.17	0.12	0.192	0.131
2-Jul-18	0.17	0.12	0.192	0.131
3-Jul-18	0.16	0.12	0.191	0.131
4-Jul-18	0.18	0.12	0.189	0.131
5-Jul-18	0.19	0.12	0.188	0.131
6-Jul-18	0.18	0.13	0.187	0.131
7-Jul-18	0.18	0.13	0.187	0.131
8-Jul-18	0.18	0.13	0.187	0.131
9-Jul-18	0.16	0.12	0.186	0.131
10-Jul-18	0.17	0.11	0.184	0.130
11-Jul-18	0.20	0.12	0.184	0.129
12-Jul-18	0.21	0.12	0.183	0.129
13-Jul-18	0.18	0.12	0.182	0.128
14-Jul-18	0.17	0.11	0.181	0.128
15-Jul-18	0.17	0.12	0.181	0.128
16-Jul-18	0.17	0.12	0.181	0.128
17-Jul-18	0.18	0.12	0.182	0.129
18-Jul-18	0.20	0.13	0.183	0.130
19-Jul-18	0.20	0.13	0.183	0.130
20-Jul-18	0.19	0.13	0.183	0.130
21-Jul-18	0.19	0.13	0.185	0.127
22-Jul-18	0.19	0.13	0.183	0.126
23-Jul-18	0.19	0.13	0.183	0.126
24-Jul-18	0.20	0.13	0.183	0.126
25-Jul-18	0.19	0.13	0.184	0.124
26-Jul-18	0.20	0.14	0.184	0.124
27-Jul-18	0.20	0.13	0.184	0.124
28-Jul-18	0.21	0.14	0.185	0.124
29-Jul-18	0.21	0.14	0.186	0.125
30-Jul-18	0.20	0.12	0.186	0.125
31-Jul-18	0.19	0.12	0.187	0.125
1-Aug-18	0.23	0.20	0.189	0.127
2-Aug-18	0.25	0.19	0.192	0.130
3-Aug-18	0.16	0.11	0.191	0.130
4-Aug-18	0.17	0.12	0.191	0.130
5-Aug-18	0.17	0.12	0.191	0.129
6-Aug-18	0.17	0.12	0.190	0.129
7-Aug-18	0.18	0.11	0.190	0.129
8-Aug-18	0.17	0.12	0.190	0.128
9-Aug-18	0.17	0.13	0.190	0.129
10-Aug-18	0.17	0.13	0.189	0.129
11-Aug-18	0.18	0.13	0.188	0.130
12-Aug-18	0.17	0.13	0.188	0.130
13-Aug-18	0.17	0.13	0.188	0.131
14-Aug-18	0.17	0.13	0.188	0.131
15-Aug-18	0.18	0.13	0.188	0.132
16-Aug-18	0.17	0.13	0.188	0.132
17-Aug-18	0.18	0.14	0.187	0.132
18-Aug-18	0.18	0.13	0.187	0.132
19-Aug-18	0.18	0.13	0.186	0.132
20-Aug-18	0.17	0.12	0.185	0.132
21-Aug-18	0.17	0.12	0.185	0.132
22-Aug-18	0.17	0.13	0.184	0.132
23-Aug-18	0.17	0.14	0.183	0.132
24-Aug-18	0.18	0.14	0.183	0.133
25-Aug-18	0.18	0.14	0.182	0.133
26-Aug-18	0.17	0.13	0.181	0.133
27-Aug-18	0.17	0.13	0.180	0.132

28-Aug-18	0.17	0.12	0.178	0.132
29-Aug-18	0.17	0.13	0.177	0.132
30-Aug-18	0.16	0.12	0.176	0.132
31-Aug-18	0.18	0.13	0.174	0.130
1-Sep-18	0.18	0.13	0.172	0.128
2-Sep-18	0.17	0.13	0.172	0.129
3-Sep-18	0.16	0.13	0.172	0.129
4-Sep-18	0.15	0.12	0.172	0.129
5-Sep-18	0.16	0.13	0.171	0.129
6-Sep-18	0.16	0.12	0.171	0.129
7-Sep-18	0.16	0.12	0.171	0.130
8-Sep-18	0.18	0.14	0.171	0.130
9-Sep-18	0.18	0.14	0.172	0.130
10-Sep-18	0.18	0.13	0.172	0.130
11-Sep-18	0.06	0.16	0.168	0.131
12-Sep-18	0.01	0.20	0.163	0.133
13-Sep-18	0.01	0.20	0.157	0.136
14-Sep-18	0.01	0.20	0.151	0.138
15-Sep-18	0.01	0.20	0.146	0.140
16-Sep-18	0.01	0.20	0.140	0.142
17-Sep-18	0.01	0.20	0.134	0.145
18-Sep-18	0.01	0.20	0.129	0.147
19-Sep-18	0.01	0.21	0.123	0.149
20-Sep-18	0.01	0.21	0.118	0.152
21-Sep-18	0.01	0.20	0.112	0.155
22-Sep-18	0.01	0.23	0.107	0.158
23-Sep-18	0.01	0.22	0.101	0.160
24-Sep-18	0.01	0.22	0.095	0.163
25-Sep-18	0.01	0.20	0.090	0.165
26-Sep-18	0.01	0.20	0.085	0.168
27-Sep-18	0.01	0.21	0.079	0.171
28-Sep-18	0.01	0.22	0.074	0.174
29-Sep-18	0.01	0.23	0.069	0.177
30-Sep-18	0.01	0.22	0.063	0.180
1-Oct-18	0.01	0.20	0.058	0.182
2-Oct-18	0.01	0.19	0.052	0.184
3-Oct-18	0.01	0.21	0.047	0.187
4-Oct-18	0.01	0.20	0.042	0.190
5-Oct-18	0.01	0.21	0.037	0.193
6-Oct-18	0.01	0.20	0.032	0.195
7-Oct-18	0.01	0.19	0.027	0.198
8-Oct-18	0.01	0.25	0.021	0.201
9-Oct-18	0.01	0.27	0.015	0.206
10-Oct-18	0.01	0.27	0.009	0.210
11-Oct-18	0.01	0.28	0.008	0.214
12-Oct-18	0.01	0.31	0.007	0.218
13-Oct-18	0.01	0.32	0.007	0.222
14-Oct-18	0.01	0.32	0.008	0.226
15-Oct-18	0.01	0.29	0.008	0.229
16-Oct-18	0.00	0.32	0.007	0.233
17-Oct-18	0.01	0.33	0.007	0.237
18-Oct-18	0.00	0.34	0.007	0.242
19-Oct-18	0.00	0.34	0.007	0.247
20-Oct-18	0.01	0.31	0.007	0.250
21-Oct-18	0.01	0.34	0.007	0.255
22-Oct-18	0.01	0.31	0.007	0.257
23-Oct-18	0.01	0.32	0.007	0.260
24-Oct-18	0.01	0.34	0.007	0.264
25-Oct-18	0.01	0.33	0.007	0.269
26-Oct-18	0.01	0.33	0.007	0.273
27-Oct-18	0.01	0.32	0.008	0.276
28-Oct-18	0.01	0.33	0.007	0.280
29-Oct-18	0.01	0.33	0.007	0.284

30-Oct-18	0.01	0.33	0.008	0.287
31-Oct-18	0.03	0.29	0.008	0.290
1-Nov-18	0.01	0.27	0.008	0.293
2-Nov-18	0.01	0.28	0.008	0.295
3-Nov-18	0.01	0.29	0.008	0.298
4-Nov-18	0.01	0.30	0.008	0.301
5-Nov-18	0.01	0.28	0.008	0.304
6-Nov-18	0.01	0.29	0.008	0.307
7-Nov-18	0.02	0.31	0.009	0.309
8-Nov-18	0.22	0.29	0.015	0.310
9-Nov-18	0.36	0.28	0.027	0.310
10-Nov-18	0.36	0.26	0.039	0.310
11-Nov-18	0.34	0.23	0.050	0.307
12-Nov-18	0.35	0.20	0.061	0.303
13-Nov-18	0.31	0.19	0.071	0.299
14-Nov-18	0.38	0.27	0.084	0.298
15-Nov-18	0.34	0.22	0.095	0.295
16-Nov-18	0.34	0.24	0.106	0.292
17-Nov-18	0.36	0.23	0.118	0.288
18-Nov-18	0.36	0.21	0.130	0.283
19-Nov-18	0.35	0.20	0.142	0.280
20-Nov-18	0.34	0.23	0.153	0.276
21-Nov-18	0.34	0.25	0.164	0.274
22-Nov-18	0.37	0.28	0.176	0.273
23-Nov-18	0.37	0.27	0.188	0.271
24-Nov-18	0.36	0.26	0.200	0.268
25-Nov-18	0.35	0.26	0.211	0.266
26-Nov-18	0.35	0.29	0.222	0.265
27-Nov-18	0.42	0.33	0.236	0.265
28-Nov-18	0.40	0.30	0.249	0.264
29-Nov-18	0.37	0.29	0.261	0.262
30-Nov-18	0.37	0.24	0.272	0.261
1-Dec-18	0.36	0.24	0.284	0.260
2-Dec-18	0.35	0.22	0.296	0.258
3-Dec-18	0.35	0.25	0.307	0.256
4-Dec-18	0.34	0.28	0.318	0.256
5-Dec-18	0.34	0.29	0.330	0.256
6-Dec-18	0.34	0.30	0.341	0.256
7-Dec-18	0.36	0.33	0.352	0.257
8-Dec-18	0.37	0.28	0.357	0.256
9-Dec-18	0.41	0.26	0.359	0.256
10-Dec-18	0.36	0.26	0.359	0.256
11-Dec-18	0.38	0.24	0.360	0.256
12-Dec-18	0.35	0.25	0.360	0.258
13-Dec-18	0.35	0.24	0.361	0.260
14-Dec-18	0.33	0.21	0.360	0.258
15-Dec-18	0.33	0.18	0.359	0.256
16-Dec-18	0.34	0.19	0.359	0.255
17-Dec-18	0.34	0.24	0.359	0.255
18-Dec-18	0.37	0.24	0.359	0.256
19-Dec-18	0.37	0.25	0.359	0.258
20-Dec-18	0.35	0.20	0.360	0.257
21-Dec-18	0.33	0.18	0.359	0.254
22-Dec-18	0.36	0.23	0.359	0.253
23-Dec-18	0.38	0.24	0.359	0.252
24-Dec-18	0.45	0.29	0.362	0.253
25-Dec-18	0.48	0.31	0.367	0.255
26-Dec-18	0.49	0.29	0.371	0.255
27-Dec-18	0.45	0.31	0.372	0.254
28-Dec-18	0.33	0.22	0.370	0.252
29-Dec-18	0.32	0.28	0.368	0.251
30-Dec-18	0.35	0.31	0.368	0.253
31-Dec-18	0.35	0.27	0.367	0.255

1-Jan-19	0.35	0.25	0.367	0.255
2-Jan-19	0.37	0.26	0.367	0.256
3-Jan-19	0.34	0.25	0.367	0.255
4-Jan-19	0.35	0.27	0.368	0.254
5-Jan-19	0.35	0.20	0.368	0.251
6-Jan-19	0.35	0.22	0.367	0.247
7-Jan-19	0.31	0.22	0.365	0.245
8-Jan-19	0.27	0.16	0.361	0.242
9-Jan-19	0.29	0.21	0.359	0.240
10-Jan-19	0.31	0.21	0.356	0.239
11-Jan-19	0.32	0.20	0.355	0.238
12-Jan-19	0.32	0.23	0.354	0.237
13-Jan-19	0.31	0.20	0.353	0.237
14-Jan-19	0.32	0.21	0.353	0.238
15-Jan-19	0.31	0.23	0.352	0.239
16-Jan-19	0.30	0.23	0.350	0.239
17-Jan-19	0.29	0.22	0.348	0.238
18-Jan-19	0.29	0.19	0.345	0.236
19-Jan-19	0.29	0.18	0.343	0.236
20-Jan-19	0.30	0.23	0.342	0.238
21-Jan-19	0.33	0.27	0.341	0.239
22-Jan-19	0.35	0.25	0.340	0.239
23-Jan-19	0.28	0.20	0.334	0.236
24-Jan-19	0.31	0.23	0.328	0.233
25-Jan-19	0.35	0.25	0.323	0.232
26-Jan-19	0.35	0.24	0.320	0.229
27-Jan-19	0.33	0.22	0.320	0.229
28-Jan-19	0.34	0.23	0.321	0.228
29-Jan-19	0.33	0.21	0.320	0.225
30-Jan-19	0.35	0.27	0.320	0.225
31-Jan-19	0.36	0.26	0.320	0.225
1-Feb-19	0.36	0.24	0.320	0.224
2-Feb-19	0.36	0.23	0.321	0.224
3-Feb-19	0.31	0.20	0.320	0.221
4-Feb-19	0.29	0.21	0.318	0.222
5-Feb-19	0.26	0.17	0.315	0.220
6-Feb-19	0.24	0.20	0.312	0.219
7-Feb-19	0.23	0.18	0.311	0.220
8-Feb-19	0.28	0.24	0.311	0.221
9-Feb-19	0.35	0.29	0.313	0.223
10-Feb-19	0.34	0.22	0.314	0.224
11-Feb-19	0.33	0.21	0.314	0.223
12-Feb-19	0.29	0.20	0.313	0.223
13-Feb-19	0.28	0.23	0.312	0.224
14-Feb-19	0.29	0.23	0.312	0.224
15-Feb-19	0.29	0.20	0.311	0.222
16-Feb-19	0.30	0.25	0.312	0.223
17-Feb-19	0.31	0.21	0.312	0.224
18-Feb-19	0.32	0.22	0.313	0.226
19-Feb-19	0.31	0.24	0.314	0.226
20-Feb-19	0.30	0.21	0.313	0.224
21-Feb-19	0.30	0.21	0.311	0.223
22-Feb-19	0.31	0.22	0.312	0.224
23-Feb-19	0.31	0.22	0.312	0.223
24-Feb-19	0.29	0.20	0.310	0.222
25-Feb-19	0.34	0.26	0.310	0.223
26-Feb-19	0.34	0.23	0.310	0.223
27-Feb-19	0.32	0.20	0.309	0.222
28-Feb-19	0.31	0.23	0.309	0.223
1-Mar-19	0.28	0.22	0.307	0.221
2-Mar-19	0.29	0.20	0.304	0.219
3-Mar-19	0.28	0.21	0.302	0.218
4-Mar-19	0.29	0.24	0.300	0.218

5-Mar-19	0.32	0.25	0.300	0.220
6-Mar-19	0.32	0.25	0.301	0.222
7-Mar-19	0.32	0.22	0.303	0.223
8-Mar-19	0.29	0.21	0.305	0.224
9-Mar-19	0.28	0.20	0.306	0.225
10-Mar-19	0.27	0.17	0.306	0.222
11-Mar-19	0.28	0.21	0.303	0.220
12-Mar-19	0.28	0.21	0.301	0.219
13-Mar-19	0.27	0.20	0.299	0.219
14-Mar-19	0.25	0.17	0.298	0.218
15-Mar-19	0.24	0.18	0.297	0.217
16-Mar-19	0.27	0.22	0.296	0.216
17-Mar-19	0.28	0.19	0.296	0.216
18-Mar-19	0.27	0.19	0.295	0.214
19-Mar-19	0.27	0.20	0.294	0.213
20-Mar-19	0.27	0.21	0.292	0.213
21-Mar-19	0.25	0.18	0.290	0.211
22-Mar-19	0.25	0.22	0.288	0.212
23-Mar-19	0.28	0.23	0.288	0.212
24-Mar-19	0.28	0.18	0.287	0.211
25-Mar-19	0.24	0.17	0.285	0.209
26-Mar-19	0.27	0.20	0.284	0.209
27-Mar-19	0.27	0.19	0.281	0.206
28-Mar-19	0.26	0.18	0.279	0.205
29-Mar-19	0.23	0.15	0.276	0.203
30-Mar-19	0.23	0.15	0.273	0.200
31-Mar-19	0.25	0.19	0.272	0.199
1-Apr-19	0.28	0.20	0.272	0.199
2-Apr-19	0.25	0.19	0.270	0.199
3-Apr-19	0.25	0.19	0.269	0.197
4-Apr-19	0.29	0.17	0.268	0.194
5-Apr-19	0.34	0.19	0.269	0.192
6-Apr-19	0.35	0.19	0.270	0.191
7-Apr-19	0.34	0.19	0.271	0.191
8-Apr-19	0.35	0.17	0.274	0.189
9-Apr-19	0.33	0.18	0.276	0.190
10-Apr-19	0.32	0.20	0.277	0.189
11-Apr-19	0.35	0.20	0.279	0.189
12-Apr-19	0.34	0.17	0.281	0.188
13-Apr-19	0.37	0.18	0.285	0.188
14-Apr-19	0.32	0.17	0.288	0.188
15-Apr-19	0.38	0.20	0.291	0.187
16-Apr-19	0.37	0.21	0.294	0.188
17-Apr-19	0.31	0.19	0.296	0.188
18-Apr-19	0.31	0.15	0.297	0.186
19-Apr-19	0.27	0.12	0.297	0.183
20-Apr-19	0.30	0.12	0.299	0.181
21-Apr-19	0.37	0.18	0.303	0.179
22-Apr-19	0.36	0.19	0.305	0.178
23-Apr-19	0.36	0.18	0.308	0.178
24-Apr-19	0.40	0.20	0.313	0.179
25-Apr-19	0.35	0.19	0.316	0.179
26-Apr-19	0.34	0.20	0.318	0.179
27-Apr-19	0.42	0.22	0.323	0.180
28-Apr-19	0.41	0.21	0.330	0.182
29-Apr-19	0.34	0.21	0.333	0.184
30-Apr-19	0.23	0.14	0.332	0.182
1-May-19	0.18	0.12	0.329	0.180
2-May-19	0.18	0.12	0.327	0.177
3-May-19	0.19	0.12	0.325	0.175
4-May-19	0.18	0.12	0.321	0.173
5-May-19	0.18	0.13	0.316	0.171
6-May-19	0.20	0.12	0.311	0.169

7-May-19	0.18	0.11	0.306	0.167
8-May-19	0.19	0.11	0.300	0.165
9-May-19	0.17	0.11	0.295	0.163
10-May-19	0.17	0.11	0.290	0.160
11-May-19	0.19	0.13	0.285	0.157
12-May-19	0.19	0.12	0.280	0.156
13-May-19	0.20	0.13	0.275	0.154
14-May-19	0.24	0.14	0.272	0.153
15-May-19	0.21	0.13	0.266	0.151
16-May-19	0.17	0.11	0.260	0.147
17-May-19	0.19	0.10	0.256	0.144
18-May-19	0.24	0.11	0.253	0.143
19-May-19	0.26	0.12	0.253	0.143
20-May-19	0.26	0.12	0.252	0.143
21-May-19	0.28	0.12	0.249	0.141
22-May-19	0.27	0.11	0.246	0.139
23-May-19	0.25	0.10	0.242	0.136
24-May-19	0.26	0.11	0.238	0.133
25-May-19	0.24	0.10	0.234	0.130
26-May-19	0.24	0.11	0.231	0.127
27-May-19	0.25	0.11	0.225	0.124
28-May-19	0.08	0.17	0.214	0.122
29-May-19	0.01	0.19	0.203	0.122
30-May-19	0.01	0.18	0.196	0.123
31-May-19	0.01	0.18	0.190	0.125
1-Jun-19	0.01	0.19	0.184	0.127
2-Jun-19	0.01	0.19	0.178	0.130
3-Jun-19	0.01	0.21	0.172	0.133
4-Jun-19	0.01	0.20	0.166	0.135
5-Jun-19	0.01	0.18	0.160	0.137
6-Jun-19	0.01	0.17	0.154	0.139
7-Jun-19	0.01	0.18	0.148	0.141
8-Jun-19	0.01	0.19	0.143	0.144
9-Jun-19	0.01	0.18	0.137	0.146
10-Jun-19	0.01	0.17	0.131	0.148
11-Jun-19	0.01	0.19	0.125	0.150
12-Jun-19	0.01	0.19	0.118	0.152
13-Jun-19	0.01	0.18	0.111	0.153
14-Jun-19	0.01	0.19	0.104	0.155
15-Jun-19	0.01	0.19	0.099	0.158
16-Jun-19	0.01	0.17	0.092	0.160
17-Jun-19	0.01	0.17	0.085	0.162
18-Jun-19	0.01	0.16	0.076	0.164
19-Jun-19	0.01	0.16	0.068	0.165
20-Jun-19	0.01	0.16	0.059	0.166
21-Jun-19	0.01	0.18	0.050	0.168
22-Jun-19	0.01	0.18	0.042	0.171
23-Jun-19	0.01	0.18	0.033	0.174
24-Jun-19	0.01	0.17	0.026	0.176
25-Jun-19	0.01	0.18	0.018	0.178
26-Jun-19	0.01	0.18	0.010	0.180
27-Jun-19	0.01	0.17	0.008	0.180
28-Jun-19	0.01	0.16	0.007	0.180
29-Jun-19	0.01	0.15	0.007	0.179
30-Jun-19	0.01	0.16	0.007	0.178
1-Jul-19	0.01	0.17	0.007	0.178
2-Jul-19	0.01	0.16	0.007	0.176
3-Jul-19	0.01	0.14	0.007	0.174
4-Jul-19	0.01	0.15	0.008	0.172
5-Jul-19	0.02	0.15	0.008	0.171
6-Jul-19	0.02	0.15	0.008	0.171
7-Jul-19	0.02	0.15	0.009	0.170
8-Jul-19	0.12	0.14	0.013	0.168

9-Jul-19	0.20	0.15	0.019	0.167
10-Jul-19	0.18	0.15	0.025	0.166
11-Jul-19	0.17	0.15	0.030	0.164
12-Jul-19	0.17	0.15	0.035	0.163
13-Jul-19	0.18	0.16	0.041	0.163
14-Jul-19	0.18	0.15	0.047	0.161
15-Jul-19	0.06	0.16	0.048	0.160
16-Jul-19	0.01	0.15	0.048	0.159
17-Jul-19	0.01	0.15	0.048	0.159
18-Jul-19	0.01	0.15	0.049	0.158
19-Jul-19	0.02	0.15	0.049	0.158
20-Jul-19	0.01	0.14	0.049	0.157
21-Jul-19	0.02	0.15	0.049	0.156
22-Jul-19	0.12	0.15	0.053	0.155
23-Jul-19	0.20	0.12	0.059	0.153
24-Jul-19	0.20	0.10	0.066	0.151
25-Jul-19	0.20	0.10	0.072	0.148
26-Jul-19	0.20	0.10	0.079	0.146
27-Jul-19	0.20	0.10	0.085	0.143
28-Jul-19	0.19	0.10	0.091	0.141
29-Jul-19	0.19	0.11	0.097	0.140
30-Jul-19	0.08	0.14	0.100	0.139
31-Jul-19	0.01	0.15	0.100	0.138
1-Aug-19	0.01	0.16	0.100	0.138
2-Aug-19	0.01	0.15	0.100	0.138
3-Aug-19	0.01	0.15	0.099	0.139
4-Aug-19	0.01	0.16	0.099	0.139
5-Aug-19	0.01	0.16	0.098	0.139
6-Aug-19	0.01	0.16	0.098	0.139
7-Aug-19	0.01	0.14	0.094	0.140
8-Aug-19	0.13	0.13	0.092	0.139
9-Aug-19	0.22	0.12	0.094	0.138
10-Aug-19	0.23	0.12	0.096	0.137
11-Aug-19	0.24	0.12	0.098	0.136
12-Aug-19	0.23	0.12	0.100	0.135
13-Aug-19	0.20	0.11	0.100	0.133
14-Aug-19	0.21	0.11	0.105	0.132
15-Aug-19	0.22	0.11	0.112	0.130
16-Aug-19	0.22	0.11	0.119	0.129
17-Aug-19	0.22	0.11	0.126	0.128
18-Aug-19	0.22	0.10	0.133	0.126
19-Aug-19	0.21	0.10	0.140	0.125
20-Aug-19	0.22	0.10	0.147	0.124
21-Aug-19	0.21	0.10	0.150	0.122
22-Aug-19	0.23	0.09	0.151	0.121
23-Aug-19	0.25	0.10	0.153	0.121
24-Aug-19	0.24	0.10	0.154	0.121
25-Aug-19	0.25	0.10	0.156	0.121
26-Aug-19	0.23	0.10	0.157	0.121
27-Aug-19	0.24	0.10	0.159	0.121
28-Aug-19	0.23	0.10	0.160	0.120
29-Aug-19	0.24	0.10	0.165	0.119
30-Aug-19	0.23	0.10	0.173	0.117
31-Aug-19	0.24	0.10	0.181	0.115
1-Sep-19	0.23	0.09	0.188	0.113
2-Sep-19	0.22	0.09	0.195	0.111
3-Sep-19	0.23	0.10	0.203	0.109
4-Sep-19	0.21	0.09	0.209	0.107
5-Sep-19	0.23	0.09	0.217	0.105
6-Sep-19	0.23	0.10	0.224	0.104
7-Sep-19	0.23	0.10	0.228	0.102
8-Sep-19	0.24	0.10	0.228	0.102
9-Sep-19	0.23	0.10	0.228	0.101

10-Sep-19	0.23	0.10	0.228	0.100
11-Sep-19	0.21	0.09	0.227	0.099
12-Sep-19	0.26	0.04	0.229	0.097
13-Sep-19	0.29	0.00	0.232	0.093
14-Sep-19	0.30	0.00	0.234	0.090
15-Sep-19	0.31	0.00	0.237	0.086
16-Sep-19	0.29	0.01	0.239	0.083
17-Sep-19	0.28	0.05	0.242	0.081
18-Sep-19	0.31	0.00	0.245	0.078
19-Sep-19	0.28	0.00	0.247	0.075
20-Sep-19	0.28	0.00	0.249	0.071
21-Sep-19	0.27	0.00	0.251	0.068
22-Sep-19	0.28	0.00	0.252	0.065
23-Sep-19	0.26	0.00	0.252	0.062
24-Sep-19	0.28	0.00	0.253	0.059
25-Sep-19	0.27	0.00	0.254	0.056
26-Sep-19	0.27	0.01	0.255	0.053
27-Sep-19	0.29	0.00	0.257	0.050
28-Sep-19	0.28	0.00	0.258	0.046
29-Sep-19	0.26	0.00	0.259	0.043
30-Sep-19	0.22	0.00	0.259	0.040
1-Oct-19	0.22	0.00	0.258	0.037
2-Oct-19	0.20	0.00	0.258	0.034
3-Oct-19	0.21	0.00	0.257	0.031
4-Oct-19	0.27	0.00	0.259	0.028
5-Oct-19	0.29	0.00	0.261	0.025
6-Oct-19	0.26	0.00	0.262	0.022
7-Oct-19	0.28	0.00	0.264	0.019
8-Oct-19	0.30	0.00	0.266	0.016
9-Oct-19	0.29	0.01	0.268	0.013
10-Oct-19	0.25	0.12	0.268	0.014
11-Oct-19	0.22	0.19	0.269	0.017
12-Oct-19	0.23	0.18	0.268	0.022
13-Oct-19	0.25	0.21	0.266	0.028
14-Oct-19	0.25	0.19	0.265	0.035
15-Oct-19	0.25	0.22	0.263	0.042
16-Oct-19	0.24	0.25	0.261	0.050
17-Oct-19	0.27	0.25	0.261	0.057
18-Oct-19	0.27	0.23	0.259	0.064
19-Oct-19	0.24	0.25	0.258	0.073
20-Oct-19	0.24	0.27	0.257	0.082
21-Oct-19	0.25	0.24	0.256	0.090
22-Oct-19	0.23	0.17	0.254	0.095
23-Oct-19	0.27	0.18	0.255	0.101
24-Oct-19	0.30	0.18	0.256	0.107
25-Oct-19	0.28	0.18	0.256	0.113
26-Oct-19	0.27	0.17	0.256	0.118
27-Oct-19	0.27	0.15	0.255	0.123
28-Oct-19	0.27	0.16	0.255	0.128
29-Oct-19	0.27	0.17	0.255	0.134
30-Oct-19	0.25	0.16	0.256	0.139
31-Oct-19	0.23	0.17	0.257	0.144
1-Nov-19	0.30	0.23	0.260	0.152
2-Nov-19	0.32	0.24	0.263	0.160
3-Nov-19	0.32	0.21	0.265	0.167
4-Nov-19	0.30	0.22	0.265	0.174
5-Nov-19	0.29	0.21	0.266	0.181
6-Nov-19	0.31	0.24	0.267	0.188
7-Nov-19	0.29	0.22	0.267	0.196
8-Nov-19	0.32	0.26	0.268	0.204
9-Nov-19	0.32	0.25	0.270	0.208
10-Nov-19	0.31	0.21	0.273	0.209
11-Nov-19	0.30	0.21	0.275	0.210

12-Nov-19	0.30	0.27	0.277	0.212
13-Nov-19	0.32	0.26	0.279	0.214
14-Nov-19	0.31	0.24	0.282	0.215
15-Nov-19	0.32	0.23	0.284	0.214
16-Nov-19	0.33	0.22	0.286	0.213
17-Nov-19	0.32	0.22	0.288	0.213
18-Nov-19	0.30	0.24	0.290	0.213
19-Nov-19	0.30	0.23	0.292	0.211
20-Nov-19	0.29	0.24	0.293	0.211
21-Nov-19	0.30	0.25	0.295	0.214
22-Nov-19	0.29	0.22	0.296	0.215
23-Nov-19	0.29	0.26	0.296	0.218
24-Nov-19	0.29	0.24	0.296	0.220
25-Nov-19	0.29	0.24	0.297	0.222
26-Nov-19	0.29	0.24	0.297	0.225
27-Nov-19	0.29	0.23	0.298	0.227
28-Nov-19	0.31	0.27	0.299	0.231
29-Nov-19	0.31	0.25	0.301	0.234
30-Nov-19	0.31	0.25	0.304	0.236
1-Dec-19	0.28	0.22	0.304	0.236
2-Dec-19	0.29	0.26	0.303	0.237
3-Dec-19	0.29	0.26	0.302	0.238
4-Dec-19	0.30	0.27	0.301	0.240
5-Dec-19	0.26	0.24	0.300	0.241
6-Dec-19	0.29	0.24	0.300	0.241
7-Dec-19	0.32	0.27	0.301	0.243
8-Dec-19	0.32	0.26	0.301	0.243
9-Dec-19	0.29	0.24	0.300	0.243
10-Dec-19	0.30	0.27	0.300	0.245
11-Dec-19	0.31	0.30	0.300	0.248
12-Dec-19	0.31	0.27	0.301	0.248
13-Dec-19	0.30	0.24	0.300	0.247
14-Dec-19	0.27	0.23	0.299	0.247
15-Dec-19	0.29	0.28	0.298	0.248
16-Dec-19	0.30	0.26	0.297	0.249
17-Dec-19	0.29	0.26	0.296	0.250
18-Dec-19	0.30	0.28	0.296	0.252
19-Dec-19	0.30	0.28	0.296	0.253
20-Dec-19	0.30	0.27	0.296	0.254
21-Dec-19	0.30	0.28	0.296	0.256
22-Dec-19	0.30	0.28	0.297	0.258
23-Dec-19	0.30	0.28	0.297	0.258
24-Dec-19	0.29	0.30	0.297	0.260
25-Dec-19	0.30	0.30	0.297	0.262
26-Dec-19	0.30	0.27	0.297	0.263
27-Dec-19	0.28	0.24	0.297	0.264
28-Dec-19	0.29	0.25	0.296	0.263
29-Dec-19	0.27	0.23	0.295	0.262
30-Dec-19	0.27	0.21	0.294	0.261
31-Dec-19	0.29	0.28	0.294	0.263
			B1 30-day avg	**B2 30-day avg**
MAX			**0.403**	**0.310**
MAX +20%			**0.48**	**0.37**

ALLEGHENY COUNTY HEALTH DEPARTMENT

IN RE:

U.S. Steel Clairton Works 400 State Street Clairton, PA 15025	))))	**PLAN APPROVAL ORDER AND AGREEMENT No. 234 UPON CONSENT**

AND NOW, this 30th day of December, 1996,

WHEREAS, the Allegheny County Health Department, (hereafter referred to as "Department"), has determined that the United States Steel hereafter referred to as "USS"), Clairton, PA, Allegheny County, as the operator and the owner of a coking facility at 400 State Street, Clairton PA, 15025 (hereafter referred to as "the facility"), is a major stationary source of oxides of nitrogen volatile organic compounds, (hereafter referred to as "NO_x" and "VOCs") emissions as defined in Section 2101.20 of Article XXI, Rules and Regulations of the Allegheny County Health Department, Air Pollution Control (hereafter referred to as "Article XXI"); and

WHEREAS, the Department has determined that Section 2105.06.a. of Article XXI, entitled "Major NO_x & VOCs" is applicable to USS's operations; and

WHEREAS, USS has been in full compliance at all relevant times with all relevant requirements of Section 2105.06 of Article XXI; and

WHEREAS, USS has timely submitted to the Department all of the documents required by Section 2105.06.b of Article XXI (hereafter collectively referred to as "the Proposal"); and

WHEREAS, the Department has determined, after review, that the Proposal is complete; and

WHEREAS, the Department has further determined, after review, that the Proposal, constitutes Reasonably Available Control Technology (hereafter referred to as "RACT") for control of NO_x and VOC emissions from the facility; and

WHEREAS, the Department and USS desire to make enforceable the details of the Proposal by entry of this RACT Plan Approval Order and Agreement Upon Consent; and

WHEREAS, pursuant to Section 2109.03 of Article XXI, the Director of the Allegheny County Health Department or his designated representative may issue such orders as are necessary to aid in the enforcement of the provisions of Article XXI, notwithstanding the absence of any violation of any provision of Article XXI and of any condition causing, contributing to, or creating danger of air pollution;

NOW, THEREFORE, this day first written above, the Department, pursuant to Section 2109.03 of Article XXI, and upon agreement of the parties as hereinafter set forth, hereby issues the following RACT Plan Approval Order and Agreement upon Consent.

I. ORDER

1.1. The following process equipment shall be properly maintained and operated according to good engineering and air pollution control practices at all times:

A. Coke Batteries No. 1, 2, 3, 7, 8, 9, 13, 14, 15, 19, 20 and battery B

B. Pushing Emission Control System for the batteries specified in A. above.

C. Boilers No. 1, 2, 13, 14, R1, R2, T1 and T2

D. By-Products Plant Clean Coke Oven Gas Blanketing System and all process units blanketed by this system

E. Scot Plant Incinerator

F. Wastewater Treatment Plant

1.2. Boilers no. 1, 2, 13, 14, R1, R2, T1 and T2 shall not, at any time, exceed the following NO_x emission limitations:

Boiler:	Lbs/MMBTU:	Tons/Year:
No. 1	0.54	1,740
No. 2	0.54	1,285
No. 13	0.54	282
No. 14	0.54	282
R1	0.54	525
R2	0.54	525
T1	0.54	358
T2	0.54	358

1.3. The facility shall determine initial compliance with the NO_x Lbs/MMBTU emission limitations specified in paragraph 1.2 above for boilers no. 13, 14, R1, R2 T1 and T2 by NO_x emission testing. Such testing shall be performed every two years and conducted according to U. S. EPA approved test methods and Section 2108.02 of article XXI.

1.4. Boilers no. 1 and 2 at the facility shall have

properly maintained and operated Continuous Monitoring Systems or approved alternatives (hereafter referred to as "CEM"), meeting all requirements of Section 2108.03 of Article XXI at all times with the exception of emergency or planned outages, repairs or maintenance.

1.5. The NO_x emission limitations for boilers no. 1 and 2, specified in paragraph 1.2 above, shall be determined by a thirty day rolling average and by an twelve month rolling average of CEM data for the Lbs/MMBTU and Tons/Yr emission limitation respectively.

1.6 At no time shall the facility 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. All VOC emissions processed by the blanketing system shall be incinerated by combustion in the facility's coke batteries or boilers or by downstream consumers.

1.7. The facility shall maintain all appropriate records to demonstrate compliance with the requirements of Section 2105.06 of Article XXI and Order No. 234. Such records shall provide sufficient data and calculations to clearly demonstrate that all requirements of this section are being met.

1.8. The facility shall retain all records required by both §2105.06 of Article XXI and Order No. 234 for at least two years and they shall be made available to the Department upon request.

II. AGREEMENT

The foregoing Order shall be enforced in accordance with and is subject to the following agreement of the parties, to wit:

2.1. The contents of this Order shall be submitted to the U.S. Environmental Protection Agency as a revision to the Commonwealth of Pennsylvania's State Implementation Plan (hereafter referred to

as "SIP").

2.2. Failure to comply with any portion of this Order or Agreement is a violation of Article XXI that may subject USS to civil proceedings, including injunctive relief, by the Department.

2.3. This Order does not, in any way, preclude, limit or otherwise affect any other remedies available to the Department for violations of this Order or of Article XXI, including, but not limited to, actions to require the installation of additional pollution control equipment and the implementation of additional corrective operating practices.

2.4. USS hereby consents to the foregoing Order and hereby knowingly waives all rights to appeal said Order, and the undersigned represents that he is authorized to consent to the Order and to enter into this Agreement on behalf of USS.

NO SIP

2.5. USS acknowledges and understands that the purpose of this Agreement is to establish RACT for the control of emissions of NO_x and VOCs from this facility. USS further acknowledges and understands the possibility that the U.S. EPA may

decide to not accept the Agreement portion of the Plan Approval Order and Agreement by Consent as a revision to the Commonwealth of Pennsylvania's SIP.

IN WITNESS WHEREOF, and intending to be legally bound, the parties hereby consent to all of the terms and conditions of the foregoing Order and Agreement as of the date of the above written.

USX CORPORATION, U.S. STEEL GROUP

By: _____

(signature)

Print or type Name: Thomas W. Gattis

Title: Gen'l Mgr - Coking Ops

Date: 12/16/96

ALLEGHENY COUNTY HEALTH DEPARTMENT

By: _____ 12/30/96

Bruce W. Dixon, M.D., Director
Allegheny County Health Department

and By: _____

Thomas J. Puzniak, Engineering Manager
Air Quality Program

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1811

Reasonable Available Control Technology INSTALLATION PERMIT

Issued To:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855	**ACHD Permit#:**	**0052-I020**
		Date of Issuance:	April 24, 2020
		Expiration Date:	(See Section III.12)

Issued By: Digitally signed by JoAnn Truchan, PE Date: 2020.04.24 15:18:28 -04'00'

JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: Hafeez Ajenifuja Digitally signed by Hafeez Ajenifuja Date: 2020.04.24 15:11:04 -04'00'

Hafeez Ajenifuja
Air Quality Engineer

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AMENDMENTS:

DATE	*SECTION(S)*

I. CONTACT INFORMATION

Facility Location:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855
Permittee/Owner:	**U. S. Steel Mon Valley Works** **Clairton Plant** 400 State Street Clairton, PA 15025-1855
Permittee/Operator: **(if not Owner)**	Same as Owner
Responsible Official:	**Kurt Barshick**
Title:	General Manager
Company:	U. S. Steel Mon Valley Works
Address:	P.O. Box 878 Dravosburg, PA 15034
Telephone Number:	(412) 675-2600
Fax Number:	(412) 675-5407
Facility Contact:	**Jonelle Scheetz**
Title:	Environmental Control Engineer
Telephone Number:	(412) 233-1015
Fax Number:	(412) 233-1011
E-mail Address:	jsscheetz@uss.com

AGENCY ADDRESSES:

ACHD Contact:	**Chief Engineer** **Allegheny County Health Department** Air Quality Program 301 39th Street, Building #7 Pittsburgh, PA 15201-1811
EPA Contact:	**Enforcement Programs Section (3AP12)** **USEPA Region III** 1650 Arch Street Philadelphia, PA 19103-2029

II. FACILITY DESCRIPTION

FACILITY DESCRIPTION

U. S. Steel Mon Valley Works Clairton Plant is the largest by-products coke plant in North America. The Clairton Plant operates 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, approximately 225 million cubic feet of coke oven gas are 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 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 35 tons of elemental sulfur, and 50 tons of anhydrous ammonia. The coke produced is used in the blast furnace operations in the production of molten iron for steel making.

INSTALLATION DESCRIPTION

This installation permit is for inclusion of physical and operational conditions for subject facility pursuant to Reasonable Available Control Technology (RACT II) in section 2105.06 of Article XXI. There are no new units being added to the facility as part of this permitting action.

TABLE II-1: Emission Unit Identification

I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
P001	Coke Battery No. 1	Pushing Emission Control (PEC) Baghouse (P050 - Serves Batteries 1, 2 & 3)	517,935 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S001
P002	Coke Battery No. 2	PEC Baghouse (P050 - Serves Batteries 1, 2 & 3)	517,935 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S002
P003	Coke Battery No. 3	PEC Baghouse (P050 - Serves Batteries 1, 2 & 3)	517,935 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S003
P007	Coke Battery No. 13	PEC Baghouse (P052 - Serves Batteries 13, 14 & 15)	545,675 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S007
P008	Coke Battery No. 14	PEC Baghouse (P052 - Serves Batteries 13, 14 & 15)	545,675 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S008

I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
P009	Coke Battery No. 15	PEC Baghouse (P052 - Serves Batteries 13, 14 & 15)	545,675 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S009
P010	Coke Battery No. 19	PEC Baghouse (P053 - Serves Batteries 19 & 20)	1,002,290 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S010
P011	Coke Battery No. 20	PEC Baghouse (P053 - Serves Batteries 19 & 20)	1,002,290 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S011
P012	Coke Battery B	PEC Baghouse (P054)	1,491,025 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S012
P044	Coke Battery C	PROven® system, Pushing Emission Control Baghouse	1,379,059 tons of coal charged per year	Coal, recycled coke plant materials, and bulk density control additives	S014
P019	Desulfurization Plant	Afterburner	6,394,800 tons of coke per year	Coke oven tail gas	S023
P044	Light Oil Barge Loading	Vapor Recovery to Boiler	55,000,000 gallons per year	Light Oil, Tar, and Tar Distillates	NA
B001	Boiler No. 1 (Babcock & Wilcox)	NA	760 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B002	Boiler No. 2 (Combustion Engineering)	NA	481 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B005	R1 Boiler (Riley Stoker)	NA	229 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B006	R2 Boiler (Riley Stoker)	NA	229 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B007	T1 Boiler (Erie City Zurn)	NA	156 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B008	T2 Boiler (Erie City Zurn)	NA	156 MMBtu/hour	Coke Oven Gas and Natural Gas	NA
B010	Ammonia Flare	NA	12.5 MMBtu/hour	Propane (assist gas)	NA

DECLARATION OF POLICY

Pollution prevention is recognized as the preferred strategy (over pollution control) for reducing risk to air resources. Accordingly, pollution prevention measures should be integrated into air pollution control programs wherever possible, and the adoption by sources of cost-effective compliance strategies, incorporating pollution prevention, is encouraged. The Department will give expedited consideration to any permit modification request based on pollution prevention principles.

The permittee is subject to the terms and conditions set forth below. These terms and conditions constitute provisions of *Allegheny County Health Department Rules and Regulations, Article XXI Air Pollution Control*. The subject equipment has been conditionally approved for operation. The equipment shall be operated in conformity with the plans, specifications, conditions, and instructions which are part of your application, and may be periodically inspected for compliance by the Department. In the event that the terms and conditions of this permit or the applicable provisions of Article XXI conflict with the application for this permit, these terms and conditions and the applicable provisions of Article XXI shall prevail. Additionally, nothing in this permit relieves the permittee from the obligation to comply with all applicable Federal, State and Local laws and regulations.

III. GENERAL CONDITIONS

1. Prohibition of Air Pollution (§2101.11)

It shall be a violation of this permit to fail to comply with, or to cause or assist in the violation of, any requirement of this permit, or any order or permit issued pursuant to authority granted by Article XXI. The permittee shall not willfully, negligently, or through the failure to provide and operate necessary control equipment or to take necessary precautions, operate any source of air contaminants in such manner that emissions from such source:

a. Exceed the amounts permitted by this permit or by any order or permit issued pursuant to Article XXI;
b. Cause an exceedance of the ambient air quality standards established by Article XXI §2101.10; or
c. May reasonably be anticipated to endanger the public health, safety, or welfare.

2. Nuisances (§2101.13)

Any violation of any requirement of this Permit shall constitute a nuisance.

3. Definitions (§2101.20)

a. Except as specifically provided in this permit, terms used retain the meaning accorded them under the applicable provisions and requirements of Article XXI or the applicable federal or state regulation. Whenever used in this permit, or in any action taken pursuant to this permit, the words and phrases shall have the meanings stated, unless the context clearly indicates otherwise.

b. Unless specified otherwise in this permit or in the applicable regulation, the term "*year*" shall mean any twelve (12) consecutive months.

4. Certification (§2102.01)

Any report or compliance certification submitted under this permit shall contain written certification by a responsible official as to truth, accuracy, and completeness. This certification and any other certification required under this permit shall be signed by a responsible official of the source, and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or Article XXI, and all equivalent compliance techniques that have been approved by the Department, shall be properly installed, maintained, and operated consistent with good air pollution control practice.

6. Conditions (§2102.03.c)

It shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02, for any person to fail to comply with any terms or conditions set forth in this permit.

7. Transfers (§2102.03.e)

This permit shall not be transferable from one person to another, except in accordance with Article XXI §2102.03.e and in cases of change-in-ownership which are documented to the satisfaction of the Department, and shall be valid only for the specific sources and equipment for which this permit was issued. The transfer of permits in the case of change-in-ownership may be made consistent with the administrative permit amendment procedure of Article XXI §2103.14.b.

8. Effect (§2102.03.g)

Issuance of this permit shall not in any manner relieve any person of the duty to fully comply with the requirements of Article XXI or any other provision of law, nor shall it in any manner preclude or affect the right of the Department to initiate any enforcement action whatsoever for violations of Article XXI or this Permit, whether occurring before or after the issuance of such permit. Further, the issuance of this permit shall not be a defense to any nuisance action, nor shall such permit be construed as a certificate of compliance with the requirements of Article XXI or this Permit.

9. General Requirements (§2102.04.a)

It shall be a violation of this Permit giving rise to the remedies set forth in Article XXI §2109 for any person to install, modify, replace, reconstruct, or reactivate any source or air pollution control equipment to which this Permit applies unless either:

a. The Department has first issued an Installation Permit for such source or equipment; or

b. Such action is solely a reactivation of a source with a current Operating Permit, which is approved under §2103.13 of Article XXI.

10. Conditions (§2102.04.e)

Further, the initiation of installation, modification, replacement, reconstruction, or reactivation under this

Installation Permit and any reactivation plan shall be deemed acceptance by the source of all terms and conditions specified by the Department in this permit and plan.

11. Revocation (§2102.04.f)

a. The Department may, at any time, revoke this Installation Permit if it finds that:
   1. Any statement made in the permit application is not true, or that material information has not been disclosed in the application;
   2. The source is not being installed, modified, replaced, reconstructed, or reactivated in the manner indicated by this permit or applicable reactivation plan;
   3. Air contaminants will not be controlled to the degree indicated by this permit;
   4. Any term or condition of this permit has not been complied with;
   5. The Department has been denied lawful access to the premises or records, charts, instruments and the like as authorized by this Permit; or

b. Prior to the date on which construction of the proposed source has commenced the Department may, revoke this Installation Permit if a significantly better air pollution control technology has become available for such source, a more stringent regulation applicable to such source has been adopted, or any other change has occurred which requires a more stringent degree of control of air contaminants.

12. Term (§2102.04.g)

This Installation Permit shall expire in 18 months if construction has not commenced within such period or shall expire 18 months after such construction has been suspended, if construction is not resumed within such period. In any event, this Installation Permit shall expire upon completion of construction, except that this Installation Permit shall authorize temporary operation to facilitate shakedown of sources and air cleaning devices, to permit operations pending issuance of a related subsequent Operating Permit, or to permit the evaluation of the air contamination aspects of the source. Such temporary operation period shall be valid for a limited time, not to exceed 180 days, but may be extended for additional limited periods, each not to exceed 120 days, except that no temporary operation shall be authorized or extended which may circumvent the requirements of this Permit.

13. Annual Installation Permit Administrative Fee (§2102.10.c & e)

No later than 30 days after the date of issuance of this Installation Permit and on or before the last day of the month in which this permit was issued in each year thereafter, during the term of this permit until a subsequent corresponding Operating Permit or amended Operating Permit is properly applied for, the owner or operator of such source shall pay to the Department, in addition to all other applicable emission and administration fees, an Annual Installation Permit Administration Fee in an amount of $750.

14. Severability Requirement (§2103.12.l)

The provisions of this permit are severable, and if any provision of this permit is determined to by a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

15. Reporting Requirements (§2103.12.k)

a. The permittee shall submit reports of any required monitoring at least every six (6) months. All

instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by the Responsible Official.

b. Prompt reporting of deviations from permit requirements is required, including those attributable to upset conditions as defined in this permit and Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

c. All reports submitted to the Department shall comply with the certification requirements of General Condition III.4 above.

d. Semiannual reports required by this permit shall be submitted to the Department as follows:
   1. One semiannual report is due by July 31 of each year for the time period beginning January 1 and ending June 30.
   2. One semiannual report is due by February 1 of each year for the time period beginning July 1 and ending December 31.
   3. The first semiannual report shall be due July 31, 2020 for the time period beginning on the issuance date of this permit through June 30, 2020.

e. Reports may be emailed to the Department at aqreports@alleghenycounty.us in lieu of mailing a hard copy.

16. Minor Installation Permit Modifications (§2102.10.d)

Modifications to this Installation Permit may be applied for but only upon submission of an application with a fee in the amount of $300 and where:

a. No reassessment of any control technology determination is required; and
b. No reassessment of any ambient air quality impact is required.

17. Violations (§2104.06)

The violation of any emission standard established by this Permit shall be a violation of this Permit giving rise to the remedies provided by Article §2109.02.

18. Other Requirements Not Affected (§2105.02)

Compliance with the requirements of this permit shall not in any manner relieve any person from the duty to fully comply with any other applicable federal, state, or county statute, rule, regulation, or the like, including, but not limited to, any applicable NSPSs, NESHAPs, MACTs, or Generally Achievable Control Technology standards now or hereafter established by the EPA, and any applicable requirement of BACT or LAER as provided by Article XXI, any condition contained in this Installation Permit and/or any additional or more stringent requirements contained in an order issued to such person pursuant to Part I of Article XXI.

19. Other Rights and Remedies Preserved (§2109.02.b)

Nothing in this permit shall be construed as impairing any right or remedy now existing or hereafter created in equity, common law or statutory law with respect to air pollution, nor shall any court be deprived of such jurisdiction for the reason that such air pollution constitutes a violation of this permit

20. Penalties, Fines, and Interest (§2109.07.a)

A source that fails to pay any fee required under this Permit or article XXI when due shall pay a civil penalty of 50% of the fee amount, plus interest on the fee amount computed in accordance with of Article XXI §2109.06.a.4 from the date the fee was required to be paid. In addition, the source may have its permit revoked.

21. Appeals (§2109.10)

In accordance with State Law and County regulations and ordinances, any person aggrieved by an order or other final action of the Department issued pursuant to Article XXI shall have the right to appeal the action to the Director in accordance with the applicable County regulations and ordinances.

IV. SITE LEVEL TERMS AND CONDITIONS

1. Reporting of Upset Conditions (§2103.12.k.2)

The permittee shall promptly report all deviations from permit requirements, including those attributable to upset conditions as defined in Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

2. Visible Emissions (§2104.01.a)

Except as provided for by Article XXI §2108.01.d pertaining to a cold start, no person shall operate, or allow to be operated, any source in such manner that the opacity of visible emissions from a flue or process fugitive emissions from such source, excluding uncombined water:

a. Equal or exceed an opacity of 20% for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or,
b. Equal or exceed an opacity of 60% at any time.

3. Odor Emissions (§2104.04) (County-only enforceable)

No person shall operate, or allow to be operated, any source in such manner that emissions of malodorous matter from such source are perceptible beyond the property line.

4. Materials Handling (§2104.05)

The permittee shall not conduct, or allow to be conducted, any materials handling operation in such manner that emissions from such operation are visible at or beyond the property line.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or any order under Article XXI, and all equivalent compliance techniques approved by the Department, shall be properly installed, maintained, and operated consistently with good air pollution control practice.

6. Open Burning (§2105.50)

No person shall conduct, or allow to be conducted, the open burning of any material, except where the Department has issued an Open Burning Permit to such person in accordance with Article XXI §2105.50 or where the open burning is conducted solely for the purpose of non-commercial preparation of food for human consumption, recreation, light, ornament, or provision of warmth for outside workers, and in a manner which contributes a negligible amount of air contaminants.

7. Shutdown of Control Equipment (§2108.01.b)

a. In the event any air pollution control equipment is shut down for reasons other than a breakdown, the person responsible for such equipment shall report, in writing, to the Department the intent to shut down such equipment at least 24 hours prior to the planned shutdown. Notwithstanding the submission of such report, the equipment shall not be shut down until the approval of the Department is obtained; provided, however, that no such report shall be required if the source(s) served by such air pollution control equipment is also shut down at all times that such equipment

is shut down.

b. The Department shall act on all requested shutdowns as promptly as possible. If the Department does not take action on such requests within ten (10) calendar days of receipt of the notice, the request shall be deemed denied, and upon request, the owner or operator of the affected source shall have a right to appeal in accordance with the provisions of Article XI.

c. The prior report required by Site Level Condition IV.7.a above shall include:

1. Identification of the specific equipment to be shut down, its location and permit number (if permitted), together with an identification of the source(s) affected;
2. The reasons for the shutdown;
3. The expected length of time that the equipment will be out of service;
4. Identification of the nature and quantity of emissions likely to occur during the shutdown;
5. Measures, including extra labor and equipment, which will be taken to minimize the length of the shutdown, the amount of air contaminants emitted, or the ambient effects of the emissions;
6. Measures which will be taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impracticable to shut down or curtail the affected source(s) during the shutdown; and
7. Such other information as may be required by the Department.

8. Breakdowns (§2108.01.c)

a. In the event that any air pollution control equipment, process equipment, or other source of air contaminants breaks down in such manner as to have a substantial likelihood of causing the emission of air contaminants in violation of this permit, or of causing the emission into the open air of potentially toxic or hazardous materials, the person responsible for such equipment or source shall immediately, but in no event later than sixty (60) minutes after the commencement of the breakdown, notify the Department of such breakdown and shall, as expeditiously as possible but in no event later than seven (7) days after the original notification, provide written notice to the Department.

b. To the maximum extent possible, all oral and written notices required shall include all pertinent facts, including:

1. Identification of the specific equipment which has broken down, its location and permit number (if permitted), together with an identification of all related devices, equipment, and other sources which will be affected.
2. The nature and probable cause of the breakdown.
3. The expected length of time that the equipment will be inoperable or that the emissions will continue.
4. Identification of the specific material(s) which are being, or are likely to be emitted, together with a statement concerning its toxic qualities, including its qualities as an irritant, and its potential for causing illness, disability, or mortality.
5. The estimated quantity of each material being or likely to be emitted.
6. Measures, including extra labor and equipment, taken or to be taken to minimize the length of the breakdown, the amount of air contaminants emitted, or the ambient effects of the emissions, together with an implementation schedule.
7. Measures being taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impractical to shut down the source(s), or any part thereof, during the breakdown.

c. Notices required shall be updated, in writing, as needed to advise the Department of changes in the information contained therein. In addition, any changes concerning potentially toxic or hazardous emissions shall be reported immediately. All additional information requested by the Department shall be submitted as expeditiously as practicable.

d. Unless otherwise directed by the Department, the Department shall be notified whenever the condition causing the breakdown is corrected or the equipment or other source is placed back in operation by no later than 9:00 AM on the next County business day. Within seven (7) days thereafter, written notice shall be submitted pursuant to Paragraphs a and b above.

e. Breakdown reporting shall not apply to breakdowns of air pollution control equipment which occur during the initial startup of said equipment, provided that emissions resulting from the breakdown are of the same nature and quantity as the emissions occurring prior to startup of the air pollution control equipment.

f. In no case shall the reporting of a breakdown prevent prosecution for any violation of this permit or Article XXI.

9. Cold Start (§2108.01.d)

In the event of a cold start on any fuel-burning or combustion equipment, except stationary internal combustion engines and combustion turbines used by utilities to meet peak load demands, the person responsible for such equipment shall report in writing to the Department the intent to perform such cold start at least 24 hours prior to the planned cold start. Such report shall identify the equipment and fuel(s) involved and shall include the expected time and duration of the startup. Upon written application from the person responsible for fuel-burning or combustion equipment which is routinely used to meet peak load demands and which is shown by experience not to be excessively emissive during a cold start, the Department may waive these requirements and may instead require periodic reports listing all cold starts which occurred during the report period. The Department shall make such waiver in writing, specifying such terms and conditions as are appropriate to achieve the purposes of Article XXI. Such waiver may be terminated by the Department at any time by written notice to the applicant.

10. Monitoring of Malodorous Matter Beyond Facility Boundaries (§2104.04)

The permittee shall take all reasonable action as may be necessary to prevent malodorous matter from becoming perceptible beyond facility boundaries. Further, the permittee shall perform such observations as may be deemed necessary along facility boundaries to insure that malodorous matter beyond the facility boundary in accordance with Article XXI §2107.13 is not perceptible and record all findings and corrective action measures taken.

11. Emissions Inventory Statements (§2108.01.e & g)

a. Emissions inventory statements in accordance with §2108.01.e shall be submitted to the Department by March 15 of each year for the preceding calendar year. The Department may require more frequent submittals if the Department determines that more frequent submissions are required by the EPA or that analysis of the data on a more frequent basis is necessary to implement the requirements of Article XXI or the Clean Air Act.

b. The failure to submit any report or update within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit

giving rise to the remedies provided by Article XXI §2109.02.

12. Orders (§2108.01.f)

In addition to meeting the requirements Site Level Conditions IV.7 through IV.11, inclusive, the person responsible for any source shall, upon order by the Department, report to the Department such information as the Department may require in order to assess the actual and potential contribution of the source to air quality. The order shall specify a reasonable time in which to make such a report.

13. Violations (§2108.01.g)

The failure to submit any report or update thereof required by Site Level Conditions IV.7 through IV.12 above, inclusive, within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

14. Emissions Testing (§2108.02)

a. **Orders:** No later than 60 days after achieving full production or 120 days after startup, whichever is earlier, the permittee shall conduct, or cause to be conducted, such emissions tests as are specified by the Department to demonstrate compliance with the applicable requirements of this permit and shall submit the results of such tests to the Department in writing. Upon written application setting forth all information necessary to evaluate the application, the Department may, for good cause shown, extend the time for conducting such tests beyond 120 days after startup but shall not extend the time beyond 60 days after achieving full production. Emissions testing shall comply with all applicable requirements of Article XXI, §2108.02.e.

b. **Tests by the Department:** Notwithstanding any tests conducted pursuant to this permit, the Department or another entity designated by the Department may conduct emissions testing on any source or air pollution control equipment. At the request of the Department, the permittee shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.

c. **Testing Requirements:** No later than 45 days prior to conducting any tests required by this permit, the person responsible for the affected source shall submit for the Department's approval a written test protocol explaining the intended testing plan, including any deviations from standard testing procedures, the proposed operating conditions of the source during the test, calibration data for specific test equipment and a demonstration that the tests will be conducted under the direct supervision of persons qualified by training and experience satisfactory to the Department to conduct such tests. In addition, at least 30 days prior to conducting such tests, the person responsible shall notify the Department in writing of the time(s) and date(s) on which the tests will be conducted and shall allow Department personnel to observe such tests, record data, provide pre-weighed filters, analyze samples in a County laboratory and to take samples for independent analysis. Test results shall be comprehensively and accurately reported in the units of measurement specified by the applicable emission limitations of this permit.

d. Test methods and procedures shall conform to the applicable reference method set forth in this permit or Article XXI Part G, or where those methods are not applicable, to an alternative sampling and testing procedure approved by the Department consistent with Article XXI §2108.02.e.2.

e. **Violations:** The failure to perform tests as required by this permit or an order of the Department, the failure to submit test results within the time specified, the knowing submission of false information, the willful failure to submit complete results, or the refusal to allow the Department, upon presentation of a search warrant, to conduct tests, shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

15. Abrasive Blasting (§2105.51)

a. Except where such blasting is a part of a process requiring an operating permit , no person shall conduct or allow to be conducted, abrasive blasting or power tool cleaning of any surface, structure, or part thereof, which has a total area greater than 1,000 square feet unless such abrasive blasting complies with all applicable requirements of Article XXI §2105.51.

b. In addition to complying with all applicable provisions of §2105.51, no person shall conduct, or allow to be conducted, abrasive blasting of any surface unless such abrasive blasting also complies with all other applicable requirements of Article XXI unless such requirements are specifically addressed by §2105.51.

16. Asbestos Abatement (§2105.62, §2105.63)

In the event of removal, encasement, or encapsulation of Asbestos-Containing Material (ACM) at a facility or in the event of the demolition of any facility, the permittee shall comply with all applicable provisions of Article XXI §2105.62 and §2105.63.

17. Volatile Organic Compound Storage Tanks (§2105.12.a)

No person shall place or store, or allow to be placed or stored, a volatile organic compound having a vapor pressure of 1.5 psia or greater under actual storage conditions in any aboveground stationary storage tank having a capacity equal to or greater than 2,000 gallons but less than or equal to 40,000 gallons, unless there is in operation on such tank pressure relief valves which are set to release at the higher of 0.7 psig of pressure or 0.3 psig of vacuum or at the highest possible pressure and vacuum in accordance with State or local fire codes, National Fire Prevention Association guidelines, or other national consensus standard approved in writing by the Department. Petroleum liquid storage vessels that are used to store produced crude oil and condensate prior to lease custody transfer are exempt from these requirements.

18. Permit Source Premises (§2105.40)

a. **General.** No person shall operate, or allow to be operated, any source for which a permit is required by Article XXI Part C in such manner that emissions from any open land, roadway, haul road, yard, or other premises located upon the source or from any material being transported within such source or from any source-owned access road, haul road, or parking lot over five (5) parking spaces:

1. Are visible at or beyond the property line of such source;

2. Have an opacity of 20% or more for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or

3. Have an opacity of 60% or more at any time.

b. **Deposition on Other Premises:** Visible emissions from any solid or liquid material that has been deposited by any means from a source onto any other premises shall be considered emissions from such source within the meaning of Site Level Condition IV.18.a above.

19. Parking Lots and Roadways (§2105.42)

a. The permittee shall not maintain for use, or allow to be used, any parking lot over 50 parking spaces or used by more than 50 vehicles in any day or any other roadway carrying more than 100 vehicles in any day or 15 vehicles in any hour in such manner that emissions from such parking lot or roadway:

1. Are visible at or beyond the property line;

2. Have an opacity of 20% or more for a period or periods aggregating more than three (3) minutes in any 60 minute period; or

3. Have an opacity of 60% or more at any time.

b. Visible emissions from any solid or liquid material that has been deposited by any means from a parking lot or roadway onto any other premises shall be considered emissions from such parking lot or roadway.

c. Site Level Condition IV.19.a above shall apply during any repairs or maintenance done to such parking lot or roadway.

d. Notwithstanding any other provision of this permit, the prohibitions of Site Level Condition IV.19 may be enforced by any municipal or local government unit having jurisdiction over the place where such parking lots or roadways are located. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violations of Site Level Condition IV.19.

20. Permit Source Transport (§2105.43)

a. No person shall transport, or allow to be transported, any solid or liquid material outside the boundary line of any source for which a permit is required by Article XXI Part C in such manner that there is any visible emission, leak, spill, or other escape of such material during transport.

b. Notwithstanding any other provision of this permit, the prohibitions of Site Level Condition IV.20 may be enforced by any municipal or local government unit having jurisdiction over the place where such visible emission, leak, spill, or other escape of material during transport occurs. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violation of Site Level Condition IV.20.

21. Construction and Land Clearing (§2105.45)

a. No person shall conduct, or allow to be conducted, any construction or land clearing activities in such manner that the opacity of emissions from such activities:

1. Equal or exceed 20% for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or
2. Equal or exceed 60% at any time.

b. Notwithstanding any other provision of this permit, the prohibitions of Site Level Condition IV.21 may be enforced by any municipal or local government unit having jurisdiction over the place where such construction or land clearing activities occur. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violations of Site Level Condition IV.21.

22. Mining (§2105.46)

No person shall conduct, or allow to be conducted, any mining activities in such manner that emissions from such activities:

a. Are visible at or beyond the property line;
b. Have an opacity of 20% or more for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or,
c. Have an opacity of 60% or more at any time.

23. Demolition (§2105.47)

a. No person shall conduct, or allow to be conducted, any demolition activities in such manner that the opacity of the emissions from such activities equal or exceed 20% for a period or periods aggregating more than three (3) minutes in any 60 minute period.

b. Notwithstanding any other provisions of this permit, the prohibitions of Site Level Condition IV.23 may be enforced by any municipal or local government unit having jurisdiction over the place where such demolition activities occur. Such enforcement shall be in accordance with the laws governing such municipal or local government unit. In addition, the Department may pursue the remedies provided by Article XXI §2109.02 for any violations of Site Level Condition IV.23.

24. Fugitive Emissions (§2105.49)

The person responsible for a source of fugitive emissions, in addition to complying with all other applicable provisions of this permit shall take all reasonable actions to prevent fugitive air contaminants from becoming airborne. Such actions may include, but are not limited to:

a. The use of asphalt, oil, water, or suitable chemicals for dust control;
b. The paving and maintenance of roadways, parking lots and the like;
c. The prompt removal of earth or other material which has been deposited by leaks from transport, erosion or other means;
d. The adoption of work or other practices to minimize emissions;
e. Enclosure of the source; and
f. The proper hooding, venting, and collection of fugitive emissions.

25. Episode Plans (§2106.02)

The permittee shall upon written request of the Department, submit a source curtailment plan, consistent

with good industrial practice and safe operating procedures, designed to reduce emissions of air contaminants during air pollution episodes. Such plans shall meet the requirements of Article XXI §2106.02.

26. New Source Performance Standards (§2105.05)

a. It shall be a violation of this permit giving rise to the remedies provided by §2109.02 of Article XXI for any person to operate, or allow to be operated, any source in a manner that does not comply with all requirements of any applicable NSPS now or hereafter established by the EPA, except if such person has obtained from EPA a waiver pursuant to Section 111 or Section 129 of the Clean Air Act or is otherwise lawfully temporarily relieved of the duty to comply with such requirements.

b. Any person who operates, or allows to be operated, any source subject to any NSPS shall conduct, or cause to be conducted, such tests, measurements, monitoring and the like as is required by such standard. All notices, reports, test results and the like as are required by such standard shall be submitted to the Department in the manner and time specified by such standard. All information, data and the like which is required to be maintained by such standard shall be made available to the Department upon request for inspection and copying.

27. National Emission Standards for Hazardous Air Pollutants (§2104.08)

a. The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.*

28. Facility-wide Emission Limitations

On or before 90 days after the initial startup and commissioning of the new Cogeneration units, the permittee shall permanently shutdown the three (3) existing Boiler No. 1, Boiler No. 2 and Boiler R1. [§2102.04.b.6]

29. The permittee shall not operate, or allow to be operated, any source in such manner that unburned coke oven gas is emitted into the open air. In addition, the permittee shall not flare, mix, or combust coke oven gas, or allow such gas to be flared, mixed or combusted unless the concentration of sulfur compounds, measured as hydrogen sulfide, in such gas is less than or equal to 35 grains per hundred dry standard cubic feet of coke oven gas produced by Clairton Plant, when all sulfur emissions from the Claus Sulfur Recovery Plant and the tail gas cleaning equipment thereon, expressed as equivalent H_2S are added to the measured H_2S. The concentration of sulfur compounds specified shall include the tail-gas sulfur, measured as hydrogen sulfide, emitted from sulfur removal equipment. [§2105.21.h].

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Boilers No. 1 & 2:

Process Description: Steam Production
Facility ID: B001 & B002
Capacity: 760 MMBtu/hr; 481 MMBtu/hr
Raw Materials: Desulfurized coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. 1 shall not at any time exceed 0.48 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. Nitrogen Oxide (NO_X) emissions from each Boiler No. 2, shall not at any time exceed 0.37 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

d. The NOx emissions in conditions V.A.1.b and V.A.1.c above shall be determined by a thirty (30) day rolling average and a twelve (12) month rolling average Continuous Emission Monitoring (CEM) data for the lbs/MMBtu and tons/yr emission limitation respectively. (25 Pa Code §129.99; RACT Order No. 234, Condition 1.5; 2102.04.b.5; §2105.06.d)

e. NO_X emissions from each Boilers No. 1 or 2 shall not exceed the limitations in Table V-A-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-A-1: NO_X Emission Limitations

Process	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 1	0.48	364.80	1,598
Boiler 2	0.37	177.97	780

*A year is defined as any consecutive 12-month period.
**Based on a 30-day rolling average.

2. Testing Requirements:

a. Emissions of NO_X may be determined by the CEMs required in Condition V.A.3 below in lieu of a stack test to determine compliance with the emissions limitation of Conditions V.A.1.b, V.A.1.c and V.A.1.e above. (§2103.12.i; §2103.12.h.1; §2108.02; §2108.03; 25 Pa Code §129.100)

b. The Department reserves the right to require additional emissions testing sufficient to assure

compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 and §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. The permittee shall install, operate, and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with 25 PA Code §§139.101 - 139.111 relating to requirements for continuous in-stack monitoring for stationary sources. (§2108.03.b.2 and RACT Plan 234)

4. Record Keeping Requirements:

a. The permittee shall maintain all appropriate records to demonstrate compliance with the requirements of §2105.06. Such records shall provide sufficient data and calculations to clearly demonstrate that all requirements of §2105.06 are met. The permittee shall record and maintain such data and information required to determine compliance for the facility in a time frame consistent with the averaging period of the requirements of both §2105.06 and RACT Order No. 235. Such information shall include, but not be limited to, the following minimum information which shall be submitted to the Department as a written report at three month intervals: (§2102.04.b.5; §2108.03.d, §2105.06; 25 Pa Code §129.100; RACT Plan 234)

1. All recording and reporting required by Section 2108.03 of Article XXI and entitled "Continuous Emission Monitoring."
2. An identification of each instance during the reporting period during which emissions exceeded the applicable emission limitation rates in Condition V.A.1.b above and an identification of the reasons, if known, for such exceedance. The averaging period used for making such identification shall correspond to the averaging period specified in condition V.A.1.d above.
3. An identification of each period during which the continuous emission monitoring system was inoperative, except for zero and span drift checks, the reasons therefore, and the nature of repairs or adjustments performed or to be performed.
4. An identification of calibrations, zero and span drift checks, and other quality assurance procedures.

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2; RACT Plan 234, Condition 1.8)

5. Reporting Requirements:

a. The permittee shall report the following information semi-annually to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. The reports shall be postmarked by the 30th day following the end of the reporting period. (§2103.12.k; §2103.12.a.2.D)

1. Total monthly Fuel Combustion Unit, fuel use, per fuel type;
2. Cold start information; and
3. Non-compliance information required to be recorded by Condition V.A.4.b above

b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)

6. Work Practice Standards:

At no time shall the permittee allow Boilers No. 1 or 2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

B. Boilers R1 and R2: B005 & B006

Process Description: Steam production
Facility ID: B005 & B006
Max. Design Rate: 229 MMBtu/hr, each (Heat Input)
Capacity: 229 MMBtu/hr, each (Heat Input)
Raw Materials: Desulfurized coke oven gas
Control Device: NA

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. 1or 2, shall not at any time exceed 0.31 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. NO_X emissions from each Boilers No. R1 or R2 shall not exceed the limitations in Table V-B-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-B-1: NO_X Emission Limitations

Process	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler R1	0.31	70.99	310.94
Boiler R2	0.31	70.99	310.94

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform emissions testing on Boilers R1 and R2 at least once every two years for NO_X. Such testing shall be in accordance with EPA Methods 7 through 7E or other such methods as approved by the Department. [RACT Plan 234 and §2108.02.c; §2107.05]

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 above and Article XXI §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

None except as provided elsewhere in the permit

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: (§2103.12.j; 25 Pa Code §129.100)

1. Records of the amount of coke oven gas combusted and the H_2S content of the coke oven gas (daily, monthly and 12 months)
2. Cold starts (date, time and duration of each occurrence);
3. Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2)

5. Reporting Requirements:

a. The permittee shall report the following information semi-annually to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. (§2103.12.k; §2103.12.a.2.D)

1. Monthly and 12-month data required to be recorded by Condition V.B.4.a above;
2. Cold start information; and
3. Non-compliance information required to be recorded by Condition V.B.4.b above

b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)

6. Work Practice Standards:

At no time shall the permittee allow Boiler No. R1 or R2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

C. Boilers T1 and T2: Existing Boiler T1 & T2

Process Description: Steam production
Facility ID: B007 & B008
Max. Design Rate: 156 MMBtu/hr, each (Heat Input)
Capacity: 156 MMBtu/hr, each (Heat Input)
Raw Materials: Desulfurized coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0052 not otherwise affected by the revisions in this permit. (§2102.04.b.5; §2105.06.d)

b. Nitrogen Oxide (NO_X) emissions from each Boiler No. T1or T2, shall not at any time exceed 0.31 lb/MMBtu, with the exception of actions to mitigate emergency situations. (25 Pa Code §129.99; 2102.04.b.5; §2105.06.d)

c. NO_X emissions from each Boilers No. T1 or T2 shall not exceed the limitations in Table V-C-1 below: (25 Pa Code §129.99; §2102.04.b.5; §2105.06.d)

TABLE V-C-1: NO_X Emission Limitations

Process	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler T1	0.31	40.36	211.02
Boiler T2	0.31	40.36	211.02

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform emissions testing on Boilers T1 and T2 at least once every two years for NO_X. Such testing shall be in accordance with EPA Methods 7 through 7E or other such methods as approved by the Department. (RACT Plan 234 and §2108.02.c; §2107.05)

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Site Level Condition IV.14 above and Article XXI §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

None except as provided elsewhere in the permit

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers T1 and T2: (§2103.12.j; 25 Pa Code §129.100)

1. Records of the type and amount of fuel combusted and the H_2S content of the coke oven gas (daily, monthly and 12 months)
2. Cold starts (date, time and duration of each occurrence);
3. Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. (§2103.12.j)

c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2)

5. Reporting Requirements:

a. The permittee shall report the following information to the Department semi-annually in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report. The reports shall be postmarked by the 30th day following the end of the reporting period. (§2103.12.k; §2103.12.a.2.D)

1. Monthly and 12-month data required to be recorded by Condition V.C.4.a above;
2. Cold start information; and
3. Non-compliance information required to be recorded by Condition V.C.4.b above

b. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. (§2103.12.k)

6. Work Practice Standards:

At no time shall the permittee allow Boiler No. T1 or T2 to operate unless the subject equipment is properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; §2102.04.b.5; 25 Pa Code §129.99).

D. Process Equipment Sources

1. Work Practice Standards:

a. At no time shall the permittee operate the following equipment at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (RACT Order No. 234, Condition 1.1; 25 Pa Code §129.99; §2102.04.b.5)

1. Coke Oven Batteries No. 1, 2, 3, 13,1 4, 15, 19, 20, B and C
2. Pushing Emission Control System for the batteries specified in V.D.a.1
3. By-Product Recovery Plant
4. Desulfurization Plant (Scot Plant Incinerator}
5. Wastewater Treatment Plant

b. The coke oven batteries listed in condition V.D.1.a.1 above shall continue to comply with the NESHAP Subpart CCCCC and Subpart L work practice standard. (§63.306; 63.7300; 25 Pa Code §129.99; §2102.04.b.5)

c. The permittee shall not operate C Battery coke ovens unless the PROven® System is maintained and operated in such manner that the collector main is maintained at a negative pressure and each individual oven is maintained at the lowest positive pressure necessary to inhibit leaks of raw coke oven gas to the atmosphere from oven doors, charging port lids, and offtakes. [25 Pa Code §129.99; §2102.04.b.6]

d. 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. [§2105.06; RACT Plan 234; 25 Pa Code §129.99]

e. For the By-Product Plant, the permittee shall: [§2105.06; 25 Pa Code §129.99; §2104.08]

1. The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 61, Subpart V - *National Emission Standards for Equipment Leaks (Fugitive Emission Sources)*. [25 PA Code §129.99]

f. For the desulfurization Plant, the permittee shall: [§2105.06; 25 Pa Code §129.99]

1. Properly maintaining two Claus Plants at the coke oven gas desulfurization facility. 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 heat exchangers in the Vacuum Carbonate Units at the Clairton Works coke oven gas desulfurization facility.
5. Maintaining in good working order spare pumps in the Vacuum Carbonate Units at the coke oven gas desulfurization facility.
6. Good combustion practices.

7. Annual Tune-ups, continued operation as permitted and incineration as permitted.

E. Quench Towers:

Process Description: Water quenching of incandescent coke
Raw Materials: Incandescent coke, water
Control Device: Baffles installed in the quench towers to capture entrained water droplets

1. Work Practice Standards:

a. At no time shall the permittee operate the following quench towers at the facility unless they are properly operated and maintained according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (25 Pa Code §129.99; §2102.04.b.5)

Source ID	Description	Rating
P013	Quench Tower No. 1	1,553,805 tons/yr of coal
P015	Quench Tower No. 5	1,637,025 tons/yr of coal
P016	Quench Tower No. 7	2,004,580 tons/yr of coal
P017	Quench Tower B	1,491,025 tons/yr of coal
P046	Quench Tower C	1,379,059 tons/yr of coal
P051	5A Quench Tower	1,270,200 tons/yr of coal
P046	7A Quench Tower	1,555,630 tons/yr of coal

b. The permittee shall be in compliance with the quench tower work practice standards, and operation and maintenance requirements of NEESHAP 40 CFR 63, Subpart CCCCC at all times, except during periods of startup, shutdown, and malfunction as defined in §63.2. [25 Pa Code §129.99; §2103.12.h.6; §63.7295(b) & (c)]

F. Emergency Flare:

1. Work Practice Standards:

a. The permittee properly operates and maintained the emergency flare according to good engineering and air pollution control practices by performing regular maintenance with the exception of actions to mitigate emergency conditions. (25 Pa Code §129.99; §2102.04.b.5)

b. The permittee shall maintain and operate the flare according to flare minimization plan that includes (25 Pa Code §129.99; §2102.04.b.5)

1. A listing of all process units and ancillary equipment connected to the flare for each affected flare,
2. An evaluation of the baseline flow to the flares, not including pilot gas flow or purge gas flow.
3. A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring; and a description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring
4. The facility must follow the flare minimization plan and operate all flares in such a manner that minimizes all flaring except during emergencies, shutdowns, startups, turnarounds or essential operational needs, and
5. The plan should be updated periodically to account for changes in the operation of the flares, such as new connections to the flares or the installation of a flare gas recovery system, but the plan needs to be re-submitted to the Department only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline, or installs a flare gas recovery system.

VI. ALTERNATIVE OPERATING SCENARIOS

There are no alternative operating scenarios for this operation.

VII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the annual maximum potential RACT II NO_X emissions for Boilers B1, B2, R1, R2, T1 and T2.

TABLE VII-1: Emission Limitations Summary

Pollutant	Annual Combined Emission Limit (tons/year)*
Nitrogen Oxides (NO_X)	3,421