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**RACT 2 Case-by-Case Evaluation**

**Title V Permit No. 0050-OP16b**

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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 – Irvin Plant__________________  
RACT Plan Approval/Permit Number:  __0050-OP16b___________________________  
Plan Approval/Permit Issuance Date: ___April 16, 2020__________________________  

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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**

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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.
Title V Operating Permit
&
Federally Enforceable State Operating Permit

Issued To: U. S. Steel Mon Valley Works - Irvin Plant

Facility: U. S. Steel Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

ACHD Permit #: 0050-OP16b
Date of Issuance: December 9, 2016
Amendment Date: April 16, 2020
Expiration Date: December 8, 2021
Renewal Date: June 9, 2021

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

Prepared By: Gregson Vaux
Air Quality Engineer
V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Process P001: 80-inch Hot Strip Mill

Process Description: 80” Hot Strip Mill Reheat Furnaces, Roughing and Finishing Mills
Facility ID: P001 – P005 and P016
Max. Design Rate: 140 mmBtu/hr maximum heat input, each reheat furnace
Capacity: 3,000,000 tons of sheets per year
Raw Materials: Steel Slabs, Natural Gas and Coke Oven Gas
Control Device: None

As identified above, the 80” Hot Strip Mill includes five reheat furnaces (P001 – P005) and the roughing and finishing mills (P016).

1. Restrictions:
   a. Only coke oven gas and natural gas shall be combusted in reheat furnaces No. 1 through No. 5. [§2103.12.h.5.D]
   b. The permittee shall not operate or, allow to be operated reheat furnaces No. 1 through No. 5 such a manner that the emissions of particulate matter exceeds 7 pounds in any 60 minute period or 100 pounds in any 24-hour period [§2104.02.b]
   c. The permittee shall not operate or, allow to be operated the scale breaking/roughing and finishing mill stands in such a manner that the emissions of particulate matter exceeds 7 pounds in any 60 minute period or 100 pounds in any 24-hour period [§2104.02.b]
   d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in reheat furnaces No. 1 through No. 5, 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. [§2105.21.h.4]
   e. The permittee shall operate the 80” Hot Strip Mill scale breaking/roughing and finishing mill stands with lubricating oil, which is an oil-water emulsion and does not exceed a maximum VOC content by weight, of 1%, at any time. [RACT Order No. 258; §2104.06; 25 PA Code §129.99]
   f. Emissions from the Hot Strip Mill Reheat Furnaces No. 1 through No. 5 shall not exceed the emission limitations in Table V-A-1. [§2104.02; §2104.03; §2101.02.c.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Coke Oven Gas (lb/hr)</th>
<th>Natural Gas (lb/hr)</th>
<th>Annual Emission Limit (tons/year)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM-10</td>
<td>7.0</td>
<td>7.0</td>
<td>18.25</td>
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*A year is defined as any consecutive 12-month period.*
g. SO₂ emissions from the Hot Strip Mill Reheat Furnaces (aggregate) shall not exceed the limitations in Table V-A-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]

<table>
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<tr>
<th>30-day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>108.63</td>
<td>118.75</td>
<td>475.80</td>
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*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:

a. The permittee shall have sulfur dioxide (SO₂) emissions tests performed on the stacks of reheat furnaces No. 1 through No. 5 at least once every two years to demonstrate compliance with the mass emission limitations for the reheat furnaces No. 2 through No. 5 in condition V.A.1.g above. The test shall be conducted according to Method 6, 6A, 6B, or 6B specified in 40 CFR 60, Appendix A, and as approved by the Department. The permittee shall submit a stack test protocol to the Department for approval at least 45 days prior to the test dates. [SO₂ SIP IP 0050-1008, Condition V.A.2.a; §2108.02.b & .e]

b. The permittee shall perform emissions tests and evaluations for NOₓ, CO, and VOC on the stacks of reheat furnaces No. 1 through No. 5 to develop emission factors that can be applied to quantify NOₓ, CO, and VOC emissions. Testing for NOₓ, CO, and VOCs shall be conducted in accordance with approved EPA Methods in Appendix A of 40 CFR 60, Article XXI §2108.02, and as approved by the Department. Reports of the evaluation and stack testing results shall be submitted to the Department within 90 days of the date of the stack test. If testing results indicate emissions in excess of the thresholds identified in §2108.02.b, testing shall be conducted biennially for the applicable pollutant.

c. 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 12 entitled “Emissions Testing.” (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Condition IV.26.b above. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.A.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.A.3.a. However, if there is a change to the current operating
4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment:
   [RACT Order No. 258; 25 PA Code §129.100]
   1) The date of the annual tune-up;
   2) The name of the service company and/or individuals performing the annual tune-up;
   3) The operating rate or load after the annual tune-up; and
   4) The CO and NOx emission rate before and after the annual tune-up

b. The permittee shall maintain hourly, monthly and 12 month rolling totals of the fuel type (COG &
   natural gas), and fuel usage and hourly H2S concentration expressed in grains per 100 dscf for each
   80" Hot Strip Mill reheat furnace. [§2103.12.h.5.B; §2103.12.j; SIP IP 0050-1008, Condition
   V.A.4.a; 25 PA Code §129.100]

c. The permittee shall maintain sufficient documentation to demonstrate compliance with the VOC
   requirements in RACT Order No. 258 for the 80" Hot Strip Mill. Compliance with this RACT
   requirement may be demonstrated by documentation from all suppliers of oils for the 80" Hot Strip
   Mill that includes the VOC content of these oils. [§2103.12.j, 25 PA Code §129.100]

d. 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, 25 PA Code
   §129.100]

5. Reporting Requirements:

a. The permittee shall provide semi-annual reports, as specified in Condition III.15 above, of the type
   and amount of each fuel combusted in the reheat furnace required by Condition V.A.4.a.  
   [§2103.12.k]

b. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar
   day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All
   instances of non-compliance with the conditions of this permit along with all corrective action taken
   to restore the subject equipment to compliance shall be reported.  [§2103.12.k; §2103.12.j; SIP IP
   0050-1008, Condition V.A.5.a]

c. Reporting instances of non-compliance in accordance with Condition V.A.5.b above, does not
   relieve the permittee of the requirement to report breakdowns in accordance with Site Level
   Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on each furnace once every twelve
   (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include:
   [RACT Order No. 258; 25 PA Code §129.99]

   1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment,
      including the burners and moving parts necessary for proper operation as specified by the
      manufacturer;
   2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total
emissions of NOX, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

   None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
D. Process P008: No. 3 Five Stand Cold Reduction Mill

Process Description: Process P008 consists of steel roll uncoilers, cold reduction mill stands, steel roll hydraulic shear, and a roll coiler.

Facility ID:  P008
Max. Design Rate:  3,767,676 tons of steel coils per year
Capacity:  2,500,000 tons of steel coils per year
Raw Materials: Steel Coils
Control Device:  Cyclonic Mist Eliminator

As identified above, Process P008 consists of following types of equipment: steel roll uncoilers, cold reduction mill stands, steel coil hydraulic shear, and a roll coiler.

I. Restrictions - Installation Permits, Standards for Issuance, BACT

a. The permittee shall not, operate or allow to be operated, the cold reduction mill unless the five mill stands are equipped with a capture system that exhausts to a mist eliminator control system. The collection and control system shall be properly maintained and operated, controlling oil mist emissions from the cold reduction mill, according to the following specifications while the line is in operation: [Installation Permit No. 0050-I002a, §2102.04.b.6, and 25 PA Code §129.99]

1) The capture system shall have a negative air flow into the system at all times and partially enclose the mill stands with openings for the steel sheet inlet and outlet and openings for observation and access to the rollers and steel.

2) The mist eliminator control system shall be comprised of five identical cyclone mist eliminators, in parallel with a design minimum combined air flowrate of 200,000 ACFM.

3) The North and South fans shall maintain an inlet static pressure that is no more negative than -8.0" w.c.

b. The permittee shall conduct cleaning of the cyclone mist eliminators specified in Condition V.D.1.a above once every four months. This cleaning will be conducted in such a way as to thoroughly remove all material or corrosion that could decrease the mist eliminator efficiencies. Notwithstanding the previous, cleaning shall be conducted immediately following any inspection of the mist eliminators as specified in Condition V.D.3.a below if warranted by the inspection findings or when a measured inlet pressure exceeds Condition V.D.1.a.3) above. [Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

e. The permittee shall not operate or allow to be operated, the cold reduction mill in such a manner that the production during any 12 consecutive months exceeds 2,500,000 tons of steel or the daily average hourly production rate exceeds 525 tons of steel per hour based on the number of hours of operation in a day. [Installation Permit No. 0050-I002a]

d. The permittee shall operate the Cold Reduction Mill with a water-oil emulsion in which the oil content, by volume is less than or equal to 7%. The lubricating oil used in the water-oil emulsion shall have a VOC content, by weight less than or equal to 2%. [Installation Permit No. 0050-I002a; RACT Order No. 258, §2105.06; 25 PA Code §129.99]

uss Irvin-tvopb.doc 58 Amended: April 16, 2020
c. Emissions from the cold reduction mill shall not exceed the limitations in Table V-D-1 at any time:

[Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

Table V-D-1  No. 3 Five Stand Cold Reduction Mill Emission Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/ton steel rolled</th>
<th>lbs/hour</th>
<th>tons/year ¹</th>
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<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
<tr>
<td>Volatile Organic Compound</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
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</table>

¹A year is defined as any consecutive 12-month period

2. Testing Requirements:

a. The permittee shall conduct emission testing for particulate matter on the cold reduction mill oil mist capture and control system in order to determine compliance with the emissions limitations of condition V.D.1.e above. Testing shall be at least once every 5 years thereafter. Such testing shall be performed according to EPA approved test methods No. 1, No. 2, No. 3, No. 4, and No. 5 as specified in 40 CFR 60, Appendix A and in accordance with Section §2108.02 of Article XXI, or as approved by the Department. [Installation Permit No. 0050-I002a, 2/12/04 and §2108.02.a.]

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

3. Monitoring Requirements:

a. The permittee shall inspect the cold reduction mill capture system and control system specified in Condition V.D.1.a above to insure the proper operation and physical integrity of all collection and control equipment and verify negative air flow into the collection and control system daily to insure compliance with Condition V.D.1.a above. The permittee shall inspect one cyclone per week so that each cyclone is inspected a minimum of once every five weeks to insure that the cyclones are clean and free of all material or corrosion that could decrease the efficiencies of the cyclones. Notwithstanding the previous, inspections of all other cyclones shall be conducted immediately following the specified monthly single cyclone inspection if the cyclone is found to be nonfunctional, in a condition that would reduce the operating efficiency or if a measured inlet pressure exceeds Condition V.D.1.a.3) above. Any excursions from Condition V.D.1.a above shall be corrected as soon as possible. [Installation Permit No. 0050-I002a, 2/12/04; 40 C.F.R. §64.3 & 64.6; and 25 PA Code §129.100]

b. Instrumentation shall be provided that can directly measure the inlet pressure of each of the collection and control system exhaust fans to within 1/10" w.c. The inlet pressure shall be measured for each fan weekly and after any cleaning conducted on the cyclones. [Installation Permit No. 0050-I002a, 2/12/04; 40 C.F.R. §64.3 & §64.6; and 25 PA Code §129.100]
4. Record Keeping Requirements:
   
a. The permittee shall record the production and the hours of operation of the cold reduction mill on a daily basis. [Installation Permit No. 0050-I002a, 2/12/04 and §2103.12.j]
   
b. The permittee shall record the type and VOC content of all rolling oils, the percent of rolling oil in the water-oil emulsion as applied and the amount of emulsion used for the cold reduction mill on a daily basis. In addition, all emission test data from tests required by Condition V.D.2.a above shall be retained at the facility as per Condition V.D.4.d below. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.9(b); §2103.12.j; 25 PA Code §129.100]
   
c. The results of the inspections required by Condition V.D.3.a above shall be recorded weekly. The monitoring data specified Condition V.D.3.b above shall be recorded weekly and after every cyclone cleaning. Episodes of non-compliance with Conditions V.D.1.a, V.D.1.b or V.D.3.a above and corrective actions taken shall be recorded upon occurrence. All such records shall be summarized monthly. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.9(b); §2103.12.j]
   
d. 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. [Installation Permit No. 0050-I002a, 2/12/04; §§2103.12.j.2; ; 25 PA Code §129.100]

5. Reporting Requirements:
   
a. The permittee shall provide quarterly reports that contain monthly summaries of production, hours of operation, and maximum percent VOC content, by weight, of the rolling oil and the maximum percent, by weight, of the rolling oil in the water oil emulsion. The due dates of these reports are prescribed in General Condition III.15.e above. [Installation Permit No. 0050-I002a, 2/12/04; §2103.12.k.1; 40 C.F.R. §64.9(a)]
   
b. The permittee shall report the exhaust fans inlet pressures weekly measurements specified in Condition V.D.3.b above within thirty days of the end of each calendar half as required in General Condition III.15.d. §2103.12.k.1; 40 C.F.R. §64.9(a)]
   
e. The permittee shall report all instances of non-compliance with Conditions V.D.1.a, V.D.1.b, V.D.1.e, V.D.1.d, V.D.1.e, V.D.3.a, and V.D.3.b above along with all corrective action taken to restore the subject equipment to compliance, to the Department every three months in accordance with General Condition III.15.e above. [§2103.12.k.1]
   
d. Reporting instances of non-compliance in accordance with Condition V.D.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k.1]

6. Work Practice Standard:
   
a. The permittee shall maintain and operate the cold rolling mill in accordance with good air pollution control practices, by performing regular maintenance as required by condition V.D.3, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258; 25 PA Code §129.99]
7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
J. Process P015: Coke Oven Gas Flares No. 1 through No. 3 and Peachtree A & B Flare

Process Description: Four flares used for combusting excess coke oven gas.
Facility ID: P015
Max. Design Rate: 6.75 million cubic feet per day of COG, each
Capacity: 27 million cubic feet per day for four flares
Raw Materials: Coke oven gas
Control Device: Flare minimization plan

1. Restrictions:
   a. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in C.O.G. Flares No.1 to No. 3 and Peachtree Flare, 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. [§2105.21.h.4]

2. Testing Requirements:
   a. The Department reserves the right to require emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. The permittee shall measure the sulfur concentration of all coke oven gas used for combustion or flaring at the facility, a minimum of once per each successive twenty-four hour time period. The sulfur concentration shall be expressed and recorded as hydrogen sulfide. Measurements of hydrogen sulfide concentrations in coke oven gas shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy this condition (V.K.3.a). However, if there is a change to the current operating scenario, the sulfur concentration measurements required by this condition (V.K.3.a) will be taken at the Irvin Plant. [§2103.12.h.5.B]

4. Record Keeping Requirements
   a. The permittee shall maintain daily and 12 month rolling totals of the fuel usage, COG sulfur concentration (expressed as H2S) and hours of operation for Flares No.1, No. 2 and No. 3 and the Peachtree Flare: [§2103.12.h.5.B, 25 PA Code §129.100]
   b. 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; 25 PA Code §129.100]

5. Reporting Requirements:
   a. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]
   b. Reporting instances of non-compliance in accordance with V.J.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]
c. The permittee shall submit the flare minimization electronically to the Allegheny County Health Department Air Quality program within 90 days after the issuance of this permit. [§2103.12.k]

6. Work Practice Standards:

The U.S. Steel Irvin Plant shall implement a flare minimization plan for all four flares that includes:
[§2103.12.a.2.B; 25 PA Code §129.99]

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 shall 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) A primary baseline flow rate that shall 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.

d. 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.

e. The facility shall 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.

f. The plan shall 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
shall 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.

g. The flare minimization plan shall be implemented within 90 days after the issuance of this permit.

7. **Additional requirements:**

   None except as provided elsewhere.

---

**PERMIT SHIELD IN EFFECT**
K. Boiler No. 1

**Process Description:** One 79.8 MMBTUs/hr natural gas and coke oven gas fired boiler

**Facility ID:** B001

**Max. Design Rate:** 79.8 MMBtu/hr

**Capacity:** 79.8 MMBtu/hr

**Raw Materials:** Coke oven gas and natural gas

**Control Device:** N/A

This emission unit is also subject to the following requirements and restrictions:

1. **Restrictions:**
   a. Only coke oven gas and natural gas shall be combusted in Boiler No. 1. [2102.04.b.5]
   b. The permittee shall not operate, or allow to be operated Boiler No. 1 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter exceed 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   c. The permittee shall not operate, or allow to be operated Boiler No. 1 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   d. The permittee shall not operate or allow to be operated Boiler No. 1 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No.1 exceeds the rate determined by the formula: [§2104.02.a.3]

\[
A = \sum_{i} x_i a_i
\]

Where: \(A\) — allowable emissions in pounds per million BTUs of actual heat input,

\(i\) — fuel type (i.e. natural gas and coke oven gas),

\(x_i\) — fraction of total actual heat input in BTUs provided by fuel type \(i\), and

\(a_i\) — allowable emissions in pounds per million BTUs of actual heat input for fuel type \(i\), where \(a_i = 0.008\) for natural gas and \(0.02\) for coke oven gas.

   e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 1, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 1 shall not exceed the limitations specified in Table V-K-1 below, at any time: [§2104.03, §2104.02.b, §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr <strong>1</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.64</td>
<td>4.60</td>
<td>6.99</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.64</td>
<td>1.60</td>
<td>6.99</td>
</tr>
<tr>
<td>NOx</td>
<td>7.98</td>
<td>42.77</td>
<td>55.92</td>
</tr>
<tr>
<td>CO</td>
<td>7.71</td>
<td>3.38</td>
<td>33.76</td>
</tr>
<tr>
<td>VOC</td>
<td>0.51</td>
<td>0.22</td>
<td>2.24</td>
</tr>
</tbody>
</table>

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

g. SO2 emissions from Boiler No. 1 shall not exceed the limitations in Table V-K-2 below: [§§2105.21.h; SO2 SIP IP 0050-1008, Condition V.A.1.b]

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.88</td>
<td>8.92</td>
<td>34.51</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO2 State Implementation Plan (SIP) Permit Revision and USEPA SO2 Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO2 State Implementation Plan (SIP) Permit Revision and USEPA SO2 Guidance dated September 14, 2017.

2. Testing Requirements:

a. Emissions of SO2 shall be determined by converting the H2S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.K.1.g, Table V-K-2 above. [SO2 SIP IP 0050-1008, Condition V.A.2.b §2103.12.h]

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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H2S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO2 SIP IP 0050-1008, Condition V.A.3; §2103.12.h.5.B; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.K.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current
operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.K.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258, §2105.06, and §2103.12.j; 40 CFR 63, Subpart DDDDD; 25 PA Code §129.100]

1) The date of the annual tune-up;
2) The name of the service company and/or individuals performing the annual tune-up;
3) The operating rate or load after the annual tune-up;
4) The CO and NOX emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly, 12-month rolling totals of the following data for Boiler no. 1: [SO2 SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

1) Fuel type, fuel usage, hours of operation and sulfur concentration expressed as H2S in grain per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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; 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with GeneralIII.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.K.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level ConditionIV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 1 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No. 258; 25 PA Code §129.99]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and
3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

None except as provided elsewhere

PERMIT SHIELD IN EFFECT
L. Boiler No. 2

Process Description: One 84.6 MMBTUs/Hr natural gas and coke oven gas fired boiler
Facility ID: B002
Max. Design Rate: 84.6 MMBtu/hr
Capacity: 84.6 MMBtu/hr
Raw Materials: Coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in Boiler No. 2. [2102.04.b.5]

b. The permittee shall not operate, or allow to be operated Boiler No. 2 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 1 exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

c. The permittee shall not operate, or allow to be operated Boiler No. 2 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

d. The permittee shall not operate or allow to be operated Boiler No. 2 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No. 2 exceeds the rate determined by the formula: [§2104.02.a.3]

\[ A = \sum x_i a_i \]

where \( A \) = allowable emissions in pounds per million BTUs of actual heat input,
\( i \) = fuel type (i.e. natural gas and coke oven gas),
\( x_i \) = fraction of total actual heat input in BTUs provided by fuel type \( i \), and
\( a_i \) = allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_n = 0.008 \) for natural gas and 0.02 for coke oven gas.

e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 2, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 2, shall not exceed the limitations in Table V-L-1 below, at any time: 
[$\S2104.03$, $\S2104.02.b$, $\S2105.21.h.4$]

### Table V-L-1 — Boiler No. 2 Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.68</td>
<td>1.69</td>
<td>7.41</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.68</td>
<td>1.69</td>
<td>7.41</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.05</td>
<td>18.20</td>
<td>45.90</td>
</tr>
<tr>
<td>NOₓ</td>
<td>8.46</td>
<td>13.54</td>
<td>59.29</td>
</tr>
<tr>
<td>CO</td>
<td>0.17</td>
<td>4.58</td>
<td>35.80</td>
</tr>
<tr>
<td>VOC</td>
<td>0.54</td>
<td>0.23</td>
<td>2.37</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

g. SO₂ emissions from Boiler No. 1 shall not exceed the limitations in Table V-L-2 below: [$\S\S2105.21.h; SO₂ SIP-IP 0050-1008, Condition V.A.1.b$]

### TABLE V-L-2

<table>
<thead>
<tr>
<th>SO₂ Emission Limitations for Boiler 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>30-day rolling average limit (lb/hr)*</td>
</tr>
<tr>
<td>8.36</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. **Testing Requirements:**

a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.L.1.g, Table V-L-2 above. [$SO₂ SIP-IP 0050-1008, Condition V.A.2.b; §2103.12.h$]

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 §2108.02. (§2103.12.h.1)

3. **Monitoring Requirements:**

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [$SO₂ SIP-IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i$]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.L.2.a
above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.L.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart D; 25 PA Code §129.100]
      1) The date of the annual tune-up;
      2) The name of the service company and/or individuals performing the annual tune-up;
      3) The operating rate or load after the annual tune-up;
      4) The CO and NOx emission rate before and after the annual tune-up; and
      5) The excess oxygen rate after the annual tune-up.
   b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler No. 2: [SO2 SIP IP 0050-1008, Condition V.A.3; §2103.12.h.5.B]
      1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H2S in grains per 100 dsfc in coke oven gas used for combustion, for the subject boiler.
   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; 25 PA Code §129.100]

5. Reporting Requirements:
   a. The permittee shall report the concentration of H2S per 100 dsfc of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]
   b. Reporting instances of non-compliance in accordance with V.L.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:
   a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 2 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258; 25 PA Code §129.99]
      1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
      2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of carbon monoxide
(hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**

Pages 90 through 102 have been redacted.
I. Executive Summary

The U.S. Steel Irvin Works (Irvin) is defined as a major source of NO\textsubscript{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 no changes since emission sources were either exempt, additional changes were not technically or financially feasible, or changes had previously been made and were already incorporated into issued permits.

Table 1  Technically and Financially Feasible Control Options Summary for NO\textsubscript{x}

There are no technically feasible control options that are reasonably achievable for any processes at this facility.

These findings are based on the following documents:
- RACT analysis performed by ERG (U S Steel Irwin – RACTEval_2-20_15.doc)
- RACT analysis performed by U.S. Steel (0050c2014-04-04ract.pdf)

Two analyses were conducted by outside organizations: ERG and U.S. Steel. Final RACT control options were based and these two analyses and well as the Allegheny County Health Department’s separate internal evaluations. In some cases, final conclusions differ from those suggested by one or both of the outside organizations.

II. Regulatory Basis

ACHD requested all major sources of NO\textsubscript{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\textsubscript{x} and/or VOC RACT for incorporation into Allegheny County’s portion of the PA SIP. This document is the result of ACHD’s determination
III. Facility Description, Sources of NOX, and Sources of VOCs

The U.S. Steel Irvin Works is a secondary steel processing facility located in West Mifflin Borough, Allegheny County, Pennsylvania. The Irvin Plant receives steel slabs and performs one of several finishing processes on the steel slabs. The finishing processes commonly referred to as secondary steel processes, include hot and cold rolling, continuous pickling, annealing, and galvanizing. The facility is composed of an 80" hot strip mill, 64" & 84" continuous hydrochloric acid pickle lines, a cold reduction mill, HPH annealing furnaces, open coil annealing furnaces, a continuous annealing furnace, continuous galvanizing line no. 1, continuous galvanizing and aluminum coating line no. 2, a continuous terne line, four coke oven gas flares, and four natural gas/coke oven gas fired boilers.

The facility is a major source of NOX and VOCs.

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Combustion Fuel</th>
<th>Rating</th>
<th>NOx PTE (TPY)</th>
<th>NOx Presumptive Limit (RACT II)</th>
<th>VOC PTE (TPY)</th>
<th>VOC Presumptive Limit (RACT II)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P001</td>
<td>80-inch hot strip mill, five reheat furnaces¹</td>
<td>Coke Oven Gas</td>
<td>140 MMBtu/hr each furnace</td>
<td>220.1 ton/yr each furnace</td>
<td>None</td>
<td>6.2 ton/yr each furnace</td>
<td>None</td>
</tr>
<tr>
<td>P008</td>
<td>Cold Reduction Mill</td>
<td>None</td>
<td>2.5 million ton/yr steel coil</td>
<td>None</td>
<td>None</td>
<td>13.1 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>P015</td>
<td>Coke Oven Gas Flares</td>
<td>Coke Oven Gas</td>
<td>6.75 million ft³/day COG</td>
<td>180 ton/yr</td>
<td>None</td>
<td>168 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>P016</td>
<td>Roughing and Finishing Mill for 80-Inch Hot Strip Mill</td>
<td>None</td>
<td>750 tons/yr rolling oil</td>
<td>None</td>
<td>None</td>
<td>30 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler 1</td>
<td>Coke Oven Gas</td>
<td>79.8 MMBtu/hr</td>
<td>55.9 ton/yr</td>
<td>None</td>
<td>2.2 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>B002</td>
<td>Boiler 2</td>
<td>Coke Oven Gas</td>
<td>84.6 MMBtu/hr</td>
<td>59.3 ton/yr</td>
<td>None</td>
<td>2.4 ton/yr</td>
<td>None</td>
</tr>
</tbody>
</table>

Table 3 Facility Sources Subject to the Presumptive RACT II per PA Code 129.97

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Combustion Fuel</th>
<th>Rating</th>
<th>NOx PTE (TPY)</th>
<th>VOC PTE (TPY)</th>
<th>Presumptive RACT Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>P009</td>
<td>Thirty-One annealing furnaces</td>
<td>Coke Oven Gas</td>
<td>Each furnace is rated at 4.9 MMBtu/hr (&lt;20 MMBtu/hr)</td>
<td>99.82</td>
<td>4.21</td>
<td>Install, maintain, and operate the source in accordance with the manufacturer’s specifications and with good operating practices (§129.97(c)(3)) since each furnace’s heat input is less than 20 MMBtu/hr</td>
</tr>
<tr>
<td>P010</td>
<td>Sixteen annealing furnaces</td>
<td>Coke Oven Gas</td>
<td>All furnaces are rated less than 20 MMBtu/hr</td>
<td>184</td>
<td>3.4</td>
<td>Install, maintain, and operate the source in accordance with the manufacturer’s specifications and with good operating practices (§129.97(c)(3)) since each furnace’s heat input is less than 20 MMBtu/hr</td>
</tr>
<tr>
<td>P011</td>
<td>continuous annealing</td>
<td>Coke Oven Gas</td>
<td>45 MMBtu/hr</td>
<td>78.8</td>
<td>1.3</td>
<td>Presumptive RACT is a biennial tune-up (already implemented as an annual tune-up) since the furnace’s heat input is &lt; 50 MMBtu/hr §129.97(b)(1)</td>
</tr>
<tr>
<td>P012</td>
<td>no. 1 continuous galvanizing line</td>
<td>Natural Gas</td>
<td>50 MMBtu/hr (No. 1 galvanizing)</td>
<td>13.1</td>
<td>1.4</td>
<td>Presumptive RACT is 0.10 lb NOx/MMBtu §129.97(g)(1) for 50 MMBtu/hr furnace. For 18 MMBtu/hr furnace, install, maintain, and operate the source in accordance with the</td>
</tr>
</tbody>
</table>
### Table 4 Facility Sources Exempt from RACT II per PA Code 129.96(c) {< 1 TPY NO\textsubscript{X}; < 1 TPY VOC}

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Combustion Fuel</th>
<th>Rating</th>
<th>NO\textsubscript{X} PTE (TPY)</th>
<th>VOC PTE (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P002</td>
<td>64&quot; continuous coil HCL pickle</td>
<td>None</td>
<td>1.05 million tons of steel sheets/yr</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>P007</td>
<td>84&quot; continuous pickle line</td>
<td>None</td>
<td>1.58 million tons of steel sheets/yr</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>F001</td>
<td>Fugitive particulates from roads</td>
<td>None</td>
<td>3.2 miles of paved roads 0.9 miles of unpaved roads 4.3 acres of parking lots</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

### IV. RACT Determination

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

The case-by-case RACT Control Options for U.S. Steel Irvin are detailed in Table 5 (NO\textsubscript{X}) and Table 6 (VOC).

### Table 5 RACT NO\textsubscript{X} Control Comparisons

<table>
<thead>
<tr>
<th>Control Option</th>
<th>P001 Reheat Furnaces</th>
<th>P015 Coke Oven Gas Flares</th>
<th>B001</th>
<th>B002</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
</tr>
<tr>
<td>Low Nox Burners</td>
<td>tpy NO\textsubscript{X} Removed</td>
<td>129</td>
<td>14</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>1,077,006</td>
<td>115,443</td>
<td>123,062</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$8,300</td>
<td>8,300</td>
<td>8,200</td>
</tr>
<tr>
<td>Ultra Low NO\textsubscript{X} Burners</td>
<td>tpy NO\textsubscript{X} Removed</td>
<td>58.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>$715,700</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$12,300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Control Option</td>
<td>P001 Reheat Furnaces</td>
<td>P008 Cold Reduction Mill</td>
<td>P015 Coke Oven Gas Flares</td>
<td>B001</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>----------------------</td>
<td>--------------------------</td>
<td>---------------------------</td>
<td>------</td>
</tr>
<tr>
<td><strong>Cumbustion Fuel</strong></td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td></td>
</tr>
<tr>
<td><strong>Flue Gas Recirculation</strong></td>
<td>tpy NOx Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>FGR/OFR + LNB</strong></td>
<td>tpy NOx Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Low Excess Air</strong></td>
<td>tpy NOx Removed</td>
<td>Technically Infeasible</td>
<td>Previously Implemented</td>
<td>90.5</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Selective Catalytic Reduction</strong></td>
<td>tpy NOx Removed</td>
<td>Technically Infeasible</td>
<td>Previously Implemented</td>
<td>45.2</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td>3,268,500</td>
<td>3,268,500</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td>19,500</td>
<td>19,500</td>
</tr>
<tr>
<td><strong>Combustion / Performance Optimization</strong></td>
<td>tpy NOx Removed</td>
<td>Previously Implemented</td>
<td>1.1</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>6,500</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>1,000</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 6  RACT VOC Control Comparisons

<table>
<thead>
<tr>
<th>Control Option</th>
<th>P001 Reheat Furnaces</th>
<th>P008 Cold Reduction Mill</th>
<th>P015 Coke Oven Gas Flares</th>
<th>P016 Roughing and Finishing Mill</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Combustion Fuel</strong></td>
<td>Coke Oven Gas</td>
<td>None</td>
<td>Coke Oven Gas</td>
<td>None</td>
</tr>
<tr>
<td><strong>Thermal Oxidation</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>Carbon Adsorption</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>Routing to a Boiler</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>Routing to a Flare</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>Condensers</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td>Technically Infeasible</td>
</tr>
</tbody>
</table>
Control Option | P001 Reheat Furnaces | P008 Cold Reduction Mill | P015 Coke Oven Gas Flares | P016 Roughing and Finishing Mill
---|---|---|---|---
Combustion Fuel | Coke Oven Gas | None | Coke Oven Gas | None
$/ton | Technically Infeasible | | | 
Combustion / Performance Optimization
| tpy VOC Removed | Previously Implemented | Previously Implemented | | 
Cost | 0 | 0 | | 
$/ton | N/A | N/A | | 
Mist Eliminator
| tpy VOC Removed | Previously Implemented | | | 
Cost | 0 | | | 
$/ton | N/A | | | 
Flare Minimization Plan
| tpy VOC Removed | Previously Implemented | | | 
Cost | 0 | | | 
$/ton | N/A | | | 
Low-Volatility Solvents
| tpy VOC Removed | | | | 
Cost | | | | 
$/ton | | | | 
Oil Substitution
| tpy VOC Removed | Technically Infeasible | Previously Implemented, but not in permit | | 
Cost | Technically Infeasible | | 0 | 
$/ton | Technically Infeasible | | N/A | 

Identified Control Options

The following control options were identified for the Irvin case-by-case RACT analysis:

**Reheat Furnaces (P001) – NOx Control**

- **Low Excess Air (LEA)** - The steel making equipment (i.e. reheat and annealing furnaces) at U.S Steel – Irvin Plant are direct-fired sources and not typically amenable to substantive oxygen control. Furthermore, although the EPA’s Alternative Control Techniques Document for Iron and Steel Mills (ACT) reports the use of LEA for reheat furnaces, it only provides an instance for a single reheat furnace in a retrofit application, wherein the emissions reductions achieved were only 14% and these emissions reductions are not considered substantive for control. Due to these issues, LEA is not considered to be technically feasible.

- **Low NOx Burners (LNBs)** – LNBs have been previously installed in reheat furnaces at other facilities, but usually as part of a new furnace unit and combusting natural gas instead of coke oven gas as with Irvin’s reheat furnaces. In the case of retrofits, such as Irvin, results have been mixed with product quality being affected by the degree of NOx reduction and in some cases, the actual NOx emission reductions being less than indicated in the RACT/BACT/LAER Clearinghouse Database and thus the cost of emission reductions per ton to be greater than expected. When taking the previous factors into consideration, and especially the predominant usage of coke oven gas, LNBs are determined to not be economically feasible.

- **Flue gas recirculation (FGR)** – The reheat furnaces already use a portion of the exhaust stream for preheating so FGR has already been implemented in some manner. Additional FGR could be possible, no vendors were identified that would provide guarantees since FGR could affect product quality due to changes in oxygen content.
• **Over-fire air (OFA)** – Overfire air is considered to be technologically infeasible since this technology typically only works in equipment designed for contained combustion. Steel making equipment, including reheat furnaces are direct fired sources and not typically amenable to substantive excess oxygen control.

• **Selective catalytic recirculation (SCR)** – SCR has been previously installed in reheat furnaces and there was a reduction in NO\textsubscript{X} emissions, but significant issues included not achieving expected NO\textsubscript{X} reductions, rapid catalyst degradation, ammonia slip issues, exhaust heat variations, flow rate issues, gas composition issues, and oxygen content issues. SCR was considered to be technically feasible, but due to the issues listed and the high expected cost, SCR is not considered to be economically feasible.

• **Selective non-catalytic reduction (SNCR)** – In a review of the literature, there are currently no known selective non-catalytic reduction installations at iron and steel plants. Additionally, SNCR would face the same major issues as SCR (above) and thus is not considered to be an economically feasible option.

• **Combustion optimization / tune-up** – This technology is technologically and economically feasible and has been previously implemented at the Irvin reheat furnaces.

**Reheat Furnaces (P001) – VOC Control**

• **Thermal oxidation (TO)** – Thermal oxidation to control VOCs is not technically feasible due to the low VOC concentrations (less than 0.4 ppm) in the exhaust stream.

• **Carbon adsorption** – Carbon adsorption is only feasible at concentrations equal to or greater than 1000 ppm, but the VOC concentrations in the exhaust stream are less than 0.4 ppm and thus technically infeasible.

• **Routing to a boiler** – The boilers at Irvin have operating temperatures of approximately 700°F, which is too low to measurably reduce VOC concentrations and thus this option is technically infeasible.

• **Routing to a flare** – Routing to the four flares at Irvin are not expected to measurably reduce VOC concentrations and thus are technically infeasible.

• **Condensers** – A condenser requires the inlet stream to have a VOC concentration of at least 5,000 PPM and since the VOC concentration in the reheat furnaces’ waste stream is less than 0.4 ppm, this control option is technically infeasible.

• **Combustion optimization / tune-up** - This technology is technologically and economically feasible and has been previously implemented at the Irvin reheat furnaces.

**Coke Oven Gas Flares (P015) - NO\textsubscript{X} Control**

The flame is not enclosed so add-on controls are not available.

• **Good engineering practices** – This option is already implemented industry-wide.

**Coke Oven Gas Flares (P015) - VOC Control**

Based on the EPA's flare studies², 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 VOC. In general, reductions of VOC emissions from flares are based on good engineering practices and on minimization of fuel burned.

• **Good engineering practices** - This option is already implemented industry-wide.
• **Flare minimization plan** - This option is technically and economically feasible and has been previously implemented.

**Boilers 001 and 002 – NO\textsubscript{x} Control**

- **Low NO\textsubscript{x} burners (LNBs)** – LNBs were analyzed for cost effectiveness through a direct vendor quotation and the quotation received indicated that a 25% reduction in NO\textsubscript{x} emissions is achievable compared to baseline potential boiler NO\textsubscript{x} emissions of 0.16 lbs.MMBtu. Based on the economic analysis, this option is not economically feasible.
- **Selective catalytic recirculation (SCR)** – SCR units typically require at least 10% excess air to effectively reduce NO\textsubscript{x} below 10% since below this value the reduction becomes unstable. However, in the case of Irvin, the excess air is less than 5% resulting in lower expected efficiency.
- **Selective non-catalytic reduction** – Based on the economic analysis, this option is not economically feasible.
- **Low Excess Air** – This option has been previously implemented
- **Tune-up** – This option has been previously implemented

**Cold Reduction Mill (P008) – VOC Control**

- **Mist eliminators** – Mist eliminators work by employing vane plates or mesh to separate mist droplets from gas streams through mechanical impingement and the inertial impaction of droplets onto a stationary set of blades or a mesh pad and thus removing the VOC containing liquid from the gaseous exhaust stream. U.S. Steel Irvin has reported that the mist eliminator provides a 90 percent reduction in VOC emissions from the cold reduction mill stack. The facility is currently using this technology and no further emission reductions are anticipated.
- **Thermal oxidizer** – A thermal oxidizer is not considered to be technically feasible for the cold reduction mill since the majority of the mist from the operation is water resulting in the thermal oxidizer needing to be significantly large to control the operation. Additionally, the VOC concentration is the exhaust stream is less than 4 ppm, which is too low to consistently control.
- **Oil substitution** – Oil substitution for the cold reduction mill is not considered to be technically feasible since an oil with a lower VOC content cannot be identified that can be applied to the cold reduction mill and offer the same product quality performance.

**Roughing and Finishing Mill (P016) – VOC Control**

- **Mist eliminators** – Mist eliminators work by employing vane plates or mesh to separate mist droplets from gas streams through mechanical impingement and the inertial impaction of droplets onto a stationary set of blades or a mesh pad and thus removing the VOC containing liquid from the gaseous exhaust stream. The hot strip mill rolling involves rolling heated steel slabs from the 80-inch Hot Strip Mill Furnaces. The use of the oil/water emulsion at the much higher temperatures compared to the cold reduction mill, makes the use of mist eliminators and similar filtration systems not effective in oil reduction. Additionally, significant enclosures, hoods, and ducting would need to be installed, which are anticipated to significantly increase costs. Therefore, a mist eliminator is not considered technically feasible for the Hot Strip Roughing and Finishing Mill.
- **Thermal oxidizer** – A thermal oxidizer is not considered to be technically feasible for the roughing and finishing mill since the majority of the mist from the operation is water resulting in the thermal oxidizer needing to be significantly large to control the operation.
- **Oil substitution** – The use of an oil/water emulsion in the Hot Strip Mill Roughing and Finishing operations is currently limited to those that contain no more than 4% by weight VOCs. The current emulsions used by U.S. Steel – Irvin Plant is Rolkleen HM-575IRV. The VOC content of this
emulsion is 0.661% or 0.0512 lb VOC/gal. U.S. Steel – Irvin Plant is therefore currently using an oil with a lower VOC content. Therefore, oil substitution is considered technically feasible for the Hot Strip Mill, where the oil emulsion has a VOC content of less than 1% by weight.

V. **RACT Emissions Requirements**

Based on the findings in this RACT analysis, the U.S. Steel Irvin facility emissions can be summarized as follows:

<table>
<thead>
<tr>
<th>Table 7</th>
<th>RACT II Emission Reduction Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NOₓ Potential Emissions (tpy)</strong></td>
<td></td>
</tr>
<tr>
<td>Current PTE</td>
<td>RACT Reduction</td>
</tr>
<tr>
<td>1,861</td>
<td>0</td>
</tr>
<tr>
<td><strong>VOC Potential Emissions (tpy)</strong></td>
<td></td>
</tr>
<tr>
<td>Current PTE</td>
<td>RACT Reduction</td>
</tr>
<tr>
<td>271</td>
<td>0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 8</th>
<th>Summary of RACT I and RACT II Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit ID</td>
<td>Emissions Unit</td>
</tr>
<tr>
<td>---------</td>
<td>----------------</td>
</tr>
<tr>
<td>P001</td>
<td>80-inch hot strip mill, reheat furnaces 1 through 5</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>P002</td>
<td>64” continuous coil HCL pickle</td>
</tr>
<tr>
<td>P007</td>
<td>84” continuous pickle line</td>
</tr>
<tr>
<td>P008</td>
<td>no. 3 five stand cold reduction mill</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>P009</td>
<td>Thirty-one HPH annealing furnaces</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Unit ID</td>
<td>Emissions Unit</td>
</tr>
<tr>
<td>---------</td>
<td>----------------</td>
</tr>
</tbody>
</table>
| P010    | open coil annealing furnaces | 258 and Article XXI 2105.06 shall be maintained at least two years | Maintain and operate the annealing furnaces according to the manufacturers’ specifications  
Maintain and operate the annealing furnaces according to the manufacturers’ specifications  
Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years |
| P011    | continuous annealing | • Good combustion and air pollution control practices  
• Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years | Continue combushtion optimization through Good combustion and air pollution control practices  
Continue Annual combustion process adjustment. This adjustment shall meet the requirements of RACT I (Consent Order No. 258) and RACT II (§129.97(b)(1))  
Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years |
| P012    | no. 1 continuous galvanizing line | • Good combustion and air pollution control practices  
• Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years | Continue combushtion optimization through Good combustion and air pollution control practices  
NOx emissions from the P012 preheat furnace shall be less than 0.10 lb NOx/MBtu  
Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years |
| P013    | no. 2 continuous galvanizing lines | • Good combustion and air pollution control practices  
• Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years | Continue good combustion and air pollution control practices  
Maintain and operate the P013 preheat furnace according to the manufacturers’ specifications  
Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years |
| P014    | Terne Line Pot Heater (Out of Service) | | P014 is permanently Out of Service |
| P015    | coke oven gas flares | • None | Flare minimization plan |
| P016    | Roughing and Finishing Mill | • Operate rolling stand with oil-water emulsion | Continue operating rolling stand with oil-water emulsion |
| Unit ID | Emissions Unit | RACT I Conditions
Consent Order No. 258 | RACT II Conditions |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Oil shall have a maximum VOC content of 4%</td>
<td>Oil shall have a maximum VOC content of 1%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
<td>Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06, which shall be maintained at least two years</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler no. 1</td>
<td>Good combustion and air pollution control practices</td>
<td>Continue combustion optimization through Good combustion and air pollution control practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual combustion process adjustment</td>
<td>Continue Annual combustion process adjustment. This adjustment shall meet the requirements of RACT I (Consent Order No. 258) and RACT II (§129.97(b)(1))</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
<td>Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
</tr>
<tr>
<td>B002</td>
<td>Boiler no. 2</td>
<td>Good combustion and air pollution control practices</td>
<td>Continue combustion optimization through Good combustion and air pollution control practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual combustion process adjustment</td>
<td>Continue Annual combustion process adjustment. This adjustment shall meet the requirements of RACT I (Consent Order No. 258) and RACT II (§129.97(b)(1))</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
<td>Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
</tr>
<tr>
<td>B003</td>
<td>Boiler no. 3</td>
<td>Good combustion and air pollution control practices</td>
<td>Continue combustion optimization through Good combustion and air pollution control practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual combustion process adjustment</td>
<td>Continue Annual combustion process adjustment. This adjustment shall meet the requirements of RACT I (Consent Order No. 258) and RACT II (§129.97(b)(1))</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
<td>Continue to maintain records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be maintained at least two years</td>
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<tr>
<td>B004</td>
<td>Boiler no. 4</td>
<td>Good combustion and air pollution control practices</td>
<td>Continue combustion optimization through Good combustion and air pollution control practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual combustion process adjustment</td>
<td>Continue Annual combustion process adjustment. This adjustment shall meet the requirements of RACT I (Consent Order No. 258) and RACT II (§129.97(b)(1))</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Records of compliance with Consent Order No. 258 and Article XXI 2105.06 shall be</td>
<td>Continue to maintain records of compliance with Consent Order No. 258</td>
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</tbody>
</table>
As shown in Table 7 and Table 8, the RACT conditions have already been implemented in previous ACHD air quality permits resulting in no emission reduction at the U.S. Steel Irvin facility for this particular RACT analysis. All RACT I conditions, including emission limitations, emission requirements, work practices, monitoring, testing and recordkeeping still apply.

### VI. New and Revised RACT II IP/OP Permit Conditions

#### Table 9 New and Revised Permit Conditions

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Permit Condition 0050a</th>
<th>RACT II Regulations</th>
</tr>
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<tbody>
<tr>
<td>P001</td>
<td>80-inch hot strip mill, five reheat furnaces</td>
<td>Condition V.A.1.e</td>
<td>25 PA Code §129.99</td>
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<tr>
<td></td>
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<td>Condition V.A.4.a</td>
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<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.A.4.c</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.A.4.d</td>
<td>25 PA Code §129.100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Condition V.A.6.a</td>
<td>25 PA Code §129.99</td>
</tr>
<tr>
<td>P008</td>
<td>Cold Reduction Mill</td>
<td>Condition V.D.1.a</td>
<td>25 PA Code §129.99</td>
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<td></td>
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<td>Condition V.D.1.d</td>
<td>25 PA Code §129.99</td>
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<tr>
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<td></td>
<td>Condition V.D.3.a</td>
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<td>Condition V.D.3.b</td>
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<td></td>
<td></td>
<td>Condition V.D.4.a</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.D.4.b</td>
<td>25 PA Code §129.100</td>
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<td></td>
<td></td>
<td>Condition V.D.4.d</td>
<td>25 PA Code §129.100</td>
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<td></td>
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<td>Condition V.D.6.a</td>
<td>25 PA Code §129.99</td>
</tr>
<tr>
<td>P009</td>
<td>HPH Annealing Furnaces</td>
<td>Condition V.E.4.c</td>
<td>25 PA Code §129.100</td>
</tr>
<tr>
<td></td>
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<td>Condition V.E.6.a</td>
<td>25 PA Code §129.97(c)(3)</td>
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<td>P010</td>
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<td>Condition V.F.4.d</td>
<td>25 PA Code §129.100</td>
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<td>Condition V.F.6</td>
<td>25 PA Code §129.97(c)(3)</td>
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<tr>
<td>P011</td>
<td>Continuous Annealing</td>
<td>Condition V.G.4.c</td>
<td>25 PA Code §129.100</td>
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<td></td>
<td></td>
<td>Condition V.G.6.a</td>
<td>25 PA Code §129.97(b)(1)</td>
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<tr>
<td>P012</td>
<td>No. 1 Continuous Galvanizing Line</td>
<td>Condition V.H.1.c</td>
<td>25 PA Code §127.97.g.1.i</td>
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<td>Condition V.H.6.a</td>
<td>25 PA Code §129.97(c)(3)</td>
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<td>P013</td>
<td>No. 2 Continuous Galvanizing</td>
<td>Condition V.I.4.c</td>
<td>25 PA Code §129.100</td>
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<td>Condition V.I.6</td>
<td>25 PA Code §129.97(c)(3)</td>
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<tr>
<td>P015</td>
<td>Coke Oven Gas Flares</td>
<td>Condition V.J.4.a</td>
<td>25 PA Code §129.100</td>
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<td>Condition V.J.4.b</td>
<td>25 PA Code §129.100</td>
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<td>Condition V.J.5.c</td>
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<td>Condition V.J.6</td>
<td>25 PA Code §129.99</td>
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<tr>
<td>P016</td>
<td>Roughing and Finishing Mill</td>
<td>Condition V.A.1.e</td>
<td>25 PA Code §129.99</td>
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<tr>
<td></td>
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<td>Condition V.A.4.c</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.A.4.d</td>
<td>25 PA Code §129.100</td>
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<tr>
<td>Source ID</td>
<td>Description</td>
<td>Permit Condition 0050a</td>
<td>RACT II Regulations</td>
</tr>
<tr>
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<td>-------------</td>
<td>------------------------</td>
<td>---------------------</td>
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<tr>
<td>B001</td>
<td>Boiler 1</td>
<td>Condition V.K.4.a</td>
<td>25 PA Code §129.100</td>
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<td>Condition V.K.6.a</td>
<td>25 PA Code §129.99</td>
</tr>
<tr>
<td>B002</td>
<td>Boiler 2</td>
<td>Condition V.L.4.a</td>
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<tr>
<td></td>
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<td>Condition V.L.4.c</td>
<td>25 PA Code §129.100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Condition V.L.6.a</td>
<td>25 PA Code §129.99</td>
</tr>
</tbody>
</table>

All other RACT monitoring, recordkeeping and reporting requirements applicable to case-by-case RACT II determination have already be included in previous ACHD air quality permits.

1 The 2018 heat content for the COG is 539.7 btu/cf = 539.7 MMBtu/MMcf
2 EPA performed flare studies as part of development of new source performance standards for refineries (40 CFR 60, Subpart J) in 2012.
3 The conditions in this column are the conditions from Consent Order No. 258 and not the conditions (which are sometimes more stringent) found in the subsequent permits.
4 The 2018 heat content for the COG is 539.7 btu/cf = 539.7 MMBtu/MMcf
5 For P012 (continuous galvanizing line) Maximum NOx emissions under presumptive RACT (§129.97(g)(1)) are: (0.10 lb NOx/MMBtu/hr) *(8760 hrs/yr) * (1 ton/2000 lbs) = 21.9 tons/yr. Thus, P012 meets presumptive RACT
6 Condition V.H.1.c of Operating Permit 0050a (table V-H-1) issued on June 21, 2019 limits NOx emissions to 0.06 lb/MMBtu. This value is not explicitly stated, but given that the boiler is rated at 50 MMBtu/hr and the limit is 13.14 tons/yr, this is equal to 0.06 lb/MMBtu.
COMMENT/RESPONSE: The Department received 13 comments from 5 commenters. Those comments and the Department’s responses follow.

1. **COMMENT:** On page 3, please change the Facility Contacts to Nicole Heinichen” and the email to nlheinichen@uss.com”.

   **RESPONSE:** Thank you; the change has been made.

2. **COMMENT:** On page 78, please remove “25 PA Code §129.99” from Condition V.J.1.a. This condition in the Irvin Title V Permit pertains to the Article XXI citation (§2105.21.h.4) regarding hydrogen sulfide in coke oven gas. 25 PA Code §129.99 refers to an alternative RACT proposal, and the existing condition in the permit is out of the scope of RACT II.

   **RESPONSE:** Thank you; the change has been made.

3. **COMMENT:** RACT I vs. RACT II and anti-backsliding requirement: EPA has previously SIP approved RACT I for US Steel Irvin in 2001(40 CFR 52.2020 (c)(172)(i)(B)(7)). ACHD must clearly identify those RACT I units, cross-index them with the current units at US Steel Irvin and indicate which units have shutdown, been modified, been renamed 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 there is no backsliding. The comparison of the RACT I vs. RACT II requirements under §110(l) is a comparison of the entire package of emission limitations, emission requirements, work practices, monitoring, testing and recordkeeping.

   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. Although the terms RACT I and RACT II are used here and elsewhere to distinguish between those RACT requirements that were previously SIP approved and those that are being proposed now, under the Clean Air Act, there is only one RACT.

   **RESPONSE:** In Table 8, some emission unit names have been modified to more closely match the descriptions found in RACT I plan approval order and units were included that have been shut down since RACT I was implemented. Additionally, RACT II conditions in Table 8 have been slightly modified to clarify that they are continuations of RACT I conditions.

   To emphasize that there is no backsliding, RACT I conditions in Table 8 have been repeated in the RACT II Conditions column and the word “continue” has been added to emphasize that RACT I conditions are
still in effect. Emission limitations, emission requirements, work practices, monitoring, testing and recordkeeping are all at least as stringent as they previously were under RACT I.

The technical support document clearly states that all RACT I requirements still apply.

4. **COMMENT:** Clarification of RACT applicability to P016: Source ID P001 appears to include two different kinds of emission units: 5 reheat furnaces (P001 – P005, NOX emission units) and a rolling mill (P016, VOC emission unit). Using the ID numbers, please clarify the specific RACT requirements applicable to the reheat furnaces vs. the rolling mill.

**RESPONSE:** The roughing and finishing mill is now clearly referenced as P016 in the technical support document.

5. **COMMENT:** Clarification of VOC RACT for P008: Please clarify the VOC content limitation of 7% by volume applicable to the lubricating oil used at P008 (located at permit condition D.1.d), which was not discussed as part of the RACT II determination in the ACHD review memo.

**RESPONSE:** The language in condition D.1.d of the permit has been clarified.

6. **COMMENT:** VOC and NOX RACT for Coke Oven Gas Flares: The ACHD review memo states that both good engineering practices and a flare minimization plan (Table 8) have been implemented. Since the flare minimization plan has been deemed technically and economically feasible as RACT by ACHD, this plan needs to be included in the permit.

**RESPONSE:** The requirement for a flare minimization plan has been added to section V.J.6 of the permit.

7. **COMMENT:** VOC and NOX RACT technical and economic feasibility analysis: The discussion of the technical feasibility of VOC and NOX emission controls needs to include more details regarding what aspects of the specific configuration and/or operations at US Steel Irvin deem an emission control option technically infeasible. For control options or practices that already being implemented and determined to be RACT, please describe the specific practices being implemented. The ACHD memo identifies a mist eliminator as a VOC control option for the Cold Reduction Mill. Please describe how this control works and how VOC emission reductions using this control measure compares with the other control options.

For those control options determined technically feasible, the rationale for the RACT evaluation of the units being evaluated for case by case RACT needs to include more explanation of how the costs were assessed, leading to the conclusion that all technically feasible control options were not economically feasible. For example, please include more details about the method by which costs were evaluated (including, for example, assumptions of interest rate and equipment life). Note that some of the ranges for interest rates and defaults in the EPA Control Cost Manual may not be applicable or realistic for the current RACT evaluation. These may include unrealistic interest rates or inappropriate inclusion of sales or property taxes in Pennsylvania.

Additionally, please use the Source ID numbers/source descriptions to label the paragraphs in the RACT technical and economic feasibility section to clearly indicate which emission units are being evaluated.
RESPONSE: Source ID numbers were added to the technical and economic feasibility section. Text was added to the Identified Control Options section to describe the basic principle behind mist eliminators. U.S. Steel Irvin has reported that the mist eliminator provides a 90 percent reduction in VOC emissions from the cold reduction mill stack. Details of the technical and economic analyses including interest rates can be found in the ERG and U.S. Steel RACT analyses.

8. COMMENT: Adding case by case RACT citations in the permit for the emission units where applicable: The permit needs to contain the appropriate regulatory citation for the case by case RACT requirements for each of the emission units. For example, the ACHD memo at Table 8 identifies the mist eliminator as an additional component of the case by case VOC RACT requirements for this emissions unit. The permit requirement to use the mist eliminator, along with appropriate monitoring, testing and recordkeeping needs to cite 25 Pa. Code §129.99 and §129.100.

RESPONSE: The case by case citations have been added to the permit.

9. COMMENT: Existing RACT regulation applicable to F002 (Solvent Parts Cleaning): The draft permit requires F002 compliance with Article XX1 §2105.15, which is the ACHD degreasing regulation. Because this regulation is a Control Technique Guideline (CTG), certified as RACT and has been SIP approved, a case by case RACT determination is not needed for this emission unit. The citations to the case by case RACT requirements should be removed from the permit for this emissions unit.

RESPONSE: The case by case RACT citations have been removed from section V.P of the permit and the case by case RACT information has been removed from the technical support document.

10. COMMENT: Summary of Facility RACT I and II requirements: Table 8 is titled “All RACT I and RACT II Conditions” but these conditions are not always complete for every emission unit. For example, for P001, there is an additional VOC content limitation for the lubricant. ACHD should clarify the purpose of this table. Where the RACT I requirements are more stringent than the presumptive RACT II requirements at §129.97, Table 8 should indicate that those RACT I requirements remain (e.g., Boilers 1-4 with RACT I annual tune up requirements).

RESPONSE: The title of Table 8 has been changed to clarify that this table just gives a broad understanding of the old RACT requirements and the new RACT requirements. Table 9 lists the old and new permit conditions.

11. COMMENT: Appropriate citations for the §129.97 presumptive RACT subject emission units: For each of the emission units at US Steel ET that are subject to the presumptive RACT requirements at 25 Pa. Code §129.97 (Table 3 in the ACHD review memo), these citations must be added to the Title V permit, including the recordkeeping citation at §129.100. For example, the 25 Pa. Code §129.97(g)(1)(i) citation needs to be added to the requirements for P012, Continuous Galvanizing Line.

RESPONSE: The presumptive and recordkeeping citations have been added to the permit.


RESPONSE: Full technical and economic analyses can be found in the ERG and U.S. Steel RACT analyses, which are referenced in the technical support document.
13. **COMMENT:** The Department Should Provide Better Substantiation in Support of its RACT II Determination for the Boilers 001 and 002 (NO\(_x\)), as an Existing Control Option May Accommodate SCR.

**RESPONSE:** Full technical and economic analyses can be found in the ERG and U.S. Steel RACT analyses, which are referenced in the technical support document.

**LIST OF COMMENTERS**

<table>
<thead>
<tr>
<th>Name</th>
<th>Affiliation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cynthia H. Stahl</td>
<td>U.S. EPA Region III</td>
</tr>
<tr>
<td>Christopher W. Hardin</td>
<td>United States Steel Corporation</td>
</tr>
<tr>
<td>Joseph Otis Minott</td>
<td>Clean Air Council</td>
</tr>
<tr>
<td>Christopher D. Ahlers</td>
<td>Clean Air Council</td>
</tr>
<tr>
<td>Matthew Mehalik</td>
<td>Breathe Project</td>
</tr>
</tbody>
</table>
Title V Operating Permit & Federally Enforceable State Operating Permit

Issued To: U. S. Steel Mon Valley Works - Irvin Plant
Facility: U. S. Steel Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

ACHD Permit #: 0050-OP16b
Date of Issuance: December 9, 2016
Amendment Date: January 23, 2020
Expiration Date: December 8, 2021
Renewal Date: June 9, 2021

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

Prepared By: Gregson Vaux
Air Quality Engineer
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AMENDMENTS:

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<th>DATE</th>
<th>SECTION(S)</th>
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</thead>
<tbody>
<tr>
<td>05/22/19</td>
<td>Condition IV.26: Added SIP SO₂ requirements; Conditions V.A.1.g, V.E.1.f, V.F.1.o, V.G.1.h, V.K.1.g &amp; V.L.1.g: Added SO₂ emissions limit table; Condition V.A.2.a: Revised SO₂ emissions test; Conditions V.E.2.a, V.F.2.a, V.G.2.a, V.K.2.a, V.L.2.a, V.M.2.a &amp; V.M.2.a: Added SO₂ emissions test; Conditions V.A.3.a, V.E.3.a, V.F.3.a, V.G.3.a: Revised the COG monitoring condition; Conditions V.A.4.b, V.E.4.a, V.F.4.a, V.G.4.b, V.K.4.b, V.L.4.b, V.M.4.b &amp; V.N.4.b: Revised the COG concentration recordkeeping; Conditions V.A.5.b, V.E.5.b, V.F.5.a, V.G.5.a, V.K.5.a, V.L.5.a, V.M.5.a &amp; V.N.5.a: Revised the conditions.</td>
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<tr>
<td>01/22/20</td>
<td>Sections V.A, V.D, V.J, V.K, V.L, &amp; V.P: Added citations for ozone RACT II requirements.</td>
</tr>
</tbody>
</table>
I. CONTACT INFORMATION

Facility Location: U. S. Steel Mon Valley Works – Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

Permittee/Owner: U. S. Steel Mon Valley Works – Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

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) 675-7822

Facility Contact: Dan Belack
Title: Environmental Engineer
Telephone Number: (412) 675-7382
Fax Number: (412) 675-7822
E-mail Address: DBelack@uss.com

AGENCY ADDRESSES:

ACHD Contact: Chief Engineer
Allegheny County Health Department
Air Quality Program
301 39th Street, Building #7
Pittsburgh, PA 15201-1891

ACHD Engineer: Gregson Vaux
Title: Air Quality Engineer
Telephone Number: 412-578-8148
Fax Number: 412-578-8144
E-mail Address: gregson.vaux@alleghenycounty.us

EPA Contact: Enforcement Programs Section (3AP12)
USEPA Region III
1650 Arch Street
Philadelphia, PA 19103-2029
II. FACILITY DESCRIPTION

The U. S. Steel Irvin Works is a secondary steel processing facility located in West Mifflin Borough, Allegheny County, Pennsylvania. The Irvin Plant receives steel slabs and performs one of several finishing processes on the steel slabs. The finishing processes commonly referred to as secondary steel processes, include hot and cold rolling, continuous pickling, annealing, and galvanizing. The facility is composed of an 80" hot strip mill, 64" & 84" continuous hydrochloric acid pickle lines, a cold reduction mill, HPH annealing furnaces, open coil annealing furnaces, a continuous annealing furnace, continuous galvanizing line no. 1, continuous galvanizing and aluminum coating line no. 2, a continuous terne line, four coke oven gas flares, and four natural gas/coke oven gas fired boilers.

The emission units regulated by this permit are summarized in Table II-1:

<table>
<thead>
<tr>
<th>I.D.</th>
<th>SOURCE DESCRIPTION</th>
<th>CONTROL DEVICE(S)</th>
<th>MAXIMUM CAPACITY</th>
<th>FUEL/RAW MATERIAL</th>
<th>STACK I.D.</th>
</tr>
</thead>
<tbody>
<tr>
<td>P001 to P005</td>
<td>80-Inch Hot Strip Mill Reheat Furnaces No. 1 to No. 5</td>
<td>None</td>
<td>140 MMBtu/Hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP1 to SP6</td>
</tr>
<tr>
<td>P016</td>
<td>Scale Breaker Roughing Mill &amp; Finishing Mill</td>
<td>None</td>
<td>3,000,000 tons/yr</td>
<td>NA</td>
<td>Fugitive</td>
</tr>
<tr>
<td>P002</td>
<td>64-Inch Continuous Coil Hydrochloric Acid Pickle Line</td>
<td>Packed Tower Scrubber</td>
<td>1,047,174 tons/yr</td>
<td>Steel Coils, HCl Pickle Liquor</td>
<td>SP023</td>
</tr>
<tr>
<td>P007</td>
<td>84-Inch Continuous Coil Hydrochloric Acid Pickle Line</td>
<td>Packed Tower Scrubber</td>
<td>1,576,800 tons/yr</td>
<td>Steel Coils, HCl Pickle Liquor</td>
<td>SP7</td>
</tr>
<tr>
<td>P008</td>
<td>Cold Reduction Mill (Mill Stands No. 1 to No. 5)</td>
<td>Cyclone Mist Eliminator</td>
<td>3,767,676 tons/yr</td>
<td>Steel Coils and Rolling Oil Solution</td>
<td>SP9</td>
</tr>
<tr>
<td>P009</td>
<td>HPH Batch Annealing Furnaces (31 individual furnaces)</td>
<td>None</td>
<td>4.9 MMBtu/hr, each furnace</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP10</td>
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<tr>
<td>P010</td>
<td>Open Coil Annealing Furnaces No. 1 to No. 9</td>
<td>None</td>
<td>7.2 MMBtu/hr, each furnace</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnaces No. 10 to No. 13</td>
<td>None</td>
<td>9.0 MMBtu/hr, each furnace</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnace No. 14</td>
<td>None</td>
<td>5.4 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnace No. 15 &amp; No. 16</td>
<td>None</td>
<td>7.47 MMBtu/hr, each furnace</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P011</td>
<td>Continuous Annealing</td>
<td>None</td>
<td>45 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP13</td>
</tr>
<tr>
<td>P012</td>
<td>No.1 Continuous Galvanizing Preheat Furnace</td>
<td>None</td>
<td>50 MMBtu/hr</td>
<td>Natural Gas</td>
<td>SP16</td>
</tr>
<tr>
<td>P013</td>
<td>No.2 Continuous Galvanizing Galvalum Preheat Furnace</td>
<td>None</td>
<td>18 MMBtu/hr</td>
<td>Natural Gas</td>
<td>SP18</td>
</tr>
<tr>
<td>I.D.</td>
<td>SOURCE DESCRIPTION</td>
<td>CONTROL DEVICE(S)</td>
<td>MAXIMUM CAPACITY</td>
<td>FUEL/RAW MATERIAL</td>
<td>STACK I.D.</td>
</tr>
<tr>
<td>------</td>
<td>-------------------------------------------------</td>
<td>-------------------</td>
<td>---------------------------</td>
<td>------------------------------------------</td>
<td>------------</td>
</tr>
<tr>
<td>P015</td>
<td>Coke Oven Gas Flares No. 1 to No. 3 (5 lines)</td>
<td>None</td>
<td>6.75 MMSCF/d, each</td>
<td>Coke Oven Gas</td>
<td>SP20</td>
</tr>
<tr>
<td>P015</td>
<td>Peachtree Coke Oven Gas Flare (Line A and B)</td>
<td>None</td>
<td>6.75 MMSCF/d</td>
<td>Coke Oven Gas</td>
<td>SP21</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler No. 1</td>
<td>None</td>
<td>79.8 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB1</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler No. 2</td>
<td>None</td>
<td>84.6 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB2</td>
</tr>
<tr>
<td>B003</td>
<td>Boiler No. 3</td>
<td>None</td>
<td>41.6 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB3</td>
</tr>
<tr>
<td>B004</td>
<td>Boiler No. 4</td>
<td>None</td>
<td>41.6 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB3</td>
</tr>
</tbody>
</table>
Figure II-1: 80-Inch Hot Strip mill Reheat Furnaces and Roughing & Finishing Mills

- Reheat Furnace No. 1
  - SP-1 & SP-6
- Reheat Furnace No. 2
  - SP-2 & SP-6
- Reheat Furnace No. 3
  - SP-3 & SP-6
- Reheat Furnace No. 4
  - SP-4
- Reheat Furnace No. 5
  - SP-5

Roughing Mill → Descaling Operations → Finishing Mill

Fugitive-Inside Building
Figure II-2: 64-inch Continuous Coil HCl Pickle Line

Steel Coils → Tension leveler/Scale Breaker → Four (4) Continuous HCl Tanks in Series → Rinse Tank → Finished Coils

Continuous collection system covers integral with the HCl tanks

HCl to Pickle Line → Four (4) HCl Storage Tanks → Wet Packed Tower Fume Scrubber → SP023

Air Emissions → Process Flow

Packed Tower Water Scrubber → SP500
Figure II-3: 84-inch Continuous Coil Pickle Line

*The Water Wash Scrubber is a Packed Tower Water Scrubber

Steel Coil

4 Continuous Hydrochloric Acid in series Tanks

Water Wash Scrubber

SP-8

Rinse Tank

Continuous Collection Cover integra with the Tank
Figure II-4: Cold Reduction Mill

Steel coils

- Mill Stand No. 1
- Mill Stand No. 2
- Mill Stand No. 3
- Mill Stand No. 4
- Mill Stand No. 5

Capture System with Mist Eliminators

SP9
Figure II-5: HPH Annealing Furnaces

NOTES:

1. Annealing gases (hydrogen and nitrogen) are not regulated air pollutants
2. 31 individual furnaces; 29 furnace stacks and atmosphere purge stacks; 58 bases.

Combustion Stack Emissions

Annealing Gas Purge Stack [1]

Annealing Furnace [2]

Inner Cover/Coil Stacks

Steel Coils

Annealing Gas

N.G. & C.O.G.

Steel Coils

Annealing Gas
Figure II-6: Open Coil Annealing Furnaces

NOTES:

1. Annealing gases (hydrogen and nitrogen) are not regulated air pollutants.
2. Sixteen (16) moveable furnaces, 24 bases – all share a single duct.
3. Emissions from annealing furnace combustion, annealing gases, and cooling beds combine into one duct which then splits into 3 stacks.
Figure II-7: Continuous Annealing Line

- **Steel Coils**
- **Fugitive Emissions**
- **Scrap Steel**
- **Controlled Waste**
- **Wastewater Treatment**
- **Combustion Emissions**

**Uncoiler/Welder/Tension Control/Shear**

**Brush Scrubber & Hot Rinse Dryer**

**Entry Looping Tower/Pit**

**Annealing Furnace**

**1st & 2nd Cooling Zone**

**Exiting Looping Tower/Pit**

**Shear/Coiler**

**Steel Coils**

[To # 7 Temper Mill & #17 Recoiler]
Figure II-8: No. 1 Continuous Galvanizing Line

1. Steel Coils
2. Uncoiler/Welder
3. Tension Controls/Looper Pit
4. Preheat Furnace Direct Fired
5. Radiant Tube and Cooling Zone
6. Zinc Pot (Electric)
7. Strip Ovens
8. Quench Tank
9. Chemical Treatment Tank
10. Chemical Treatment Chemicals
11. Wastewater Treatment
12. Zinc Pot (Electric)
13. Quench Tank for Galvanexal
14. Exit Loop
15. Labeling
16. Oiler
17. Cooler
18. Steel Coils
19. Scrap Steel
20. Coating Oil
21. Ink & Solvents
22. Hot Air
23. Water
24. Steam

Labeled components:
- Fugitive Emissions
- Combustion Emissions
Figure II-10: No. 2 Continuous Galvanizing Line

Steel Coils → Uncoiler Shear/Welder → Caustic Cleaning → Caustic Water SWTP → Scrap Steel

Caustic Cleaning → Rinse → Scrubber Emissions → Scrubber

Rinse → Strip Dryers Steam Heat → Preheat Furnace (Electric) → Annealing Gases

Preheat Furnace (Electric) → Annealing Gases Purge → Galvalume Pot

Galvalume Pot → Galvalume & Flux Agents

Galvalume & Flux Agents → Zinc Pot

Zinc Pot → Fugitive Emissions

Steel Coils → Coiler/Shear → Strip Oilier → Air Dryer

Air Dryer → Chem Treat Tank → NDS Unit → Infrared Oven/Roll Coater

Infrared Oven/Roll Coater → 4 High Temper Mill

4 High Temper Mill → Quench Tank

Quench Tank → Drying Tower

Drying Tower → Water Air

Steel Coils → Strip Oilier → Steam Water Chemical Treatment

Chem Treat Tank → NDS Unit

Annealing Gases → Combustion Emissions

Combustion Emissions → Scrubber Water

Scrubber Water → Scrubber

Scrubber → Basement Holding Tank

Fugitive Emissions → Fugitive Emissions

Fugitive Emissions → Fugitive Emissions

Fugitive Emissions → Fugitive Emissions

Steam → N.G. Water

N.G. Water → Annealing Gases

Annealing Gases → Annealing Gases

Annealing Gases → Annealing Gases

Annealing Gases Purge → Galvalume Pot

Galvalume Pot → Galvalume & Flux Agents

Galvalume & Flux Agents → Zinc Pot

Zinc Pot → Fugitive Emissions
Figure II-11: No. 7 Temper Mill

- Steel Coils → Uncoiler
- Shear
- Single Stand 4-Hi Temper Mill
- Shear/Oiler/Coiler
- Tempered Steel Coils
- Fugitive Emissions
- Air Cleaner
- Rolling Solution
- Coating Oil
- Scrap Steel
- Wastewater Treatment
Figure II-12: No. 11 Coil and Shear Line

Steel Coils → Uncoiler → Crop Shear/Side Trimmers → Mill Stand → Uncoiler → Steel Coils

Scrap Steel

Figure II-13: No. 17 Recoiler

Steel Coils → Uncoiler → Side Trimmers → Oiler → Coiler → Steel Coils

Coating Oil → Scrap Steel for Recycle

Fugitive Emissions

Used Oil to Oil Recovery
Figure II-13: Coke Oven Gas Flares

- Coke Oven Gas Distribution Pipeline
- Excess Coke Oven Gas Regulator
  - Pilot Gas
  - No. 1 Flare
  - No. 2 Flare
  - No. 3 Flare
  - Peachtree Flare
- Combustion Emissions
Figure II-14: Boilers No. 1 through No. 4

Combustion Emissions

- Boiler No. 1
- Boiler No. 2
- Boiler No. 3
- Boiler No. 4
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 - Major Source

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. 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. 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.

c. “RACT Order No. 258” shall be defined as Plan Approval Order and Agreement Upon Consent Number 258, dated December 30, 1996.
3. **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.

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. **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 The required documentation and fee must be received by the Department at least 30 days before the intended transfer date.

6. **Term** (§2103.12.e, §2103.13.a)

   a. This permit shall remain valid for five (5) years from the date of issuance, or such other shorter period if required by the Clean Air Act, unless revoked. The terms and conditions of an expired permit shall automatically continue pending issuance of a new operating permit provided the permittee has submitted a timely and complete application and paid applicable fees required under Article XXI Part C, and the Department through no fault of the permittee is unable to issue or deny a new permit before the expiration of the previous permit.

   b. Expiration. Permit expiration terminates the source’s right to operate unless a timely and complete renewal application has been submitted consistent with the requirements of Article XXI Part C.

7. **Need to Halt or Reduce Activity Not a Defense** (§2103.12.f.2)

   It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

8. **Property Rights** (§2103.12.f.4)

   This permit does not convey any property rights of any sort, or any exclusive privilege.

9. **Duty to Provide Information** (§2103.12.f.5)

   a. The permittee shall furnish to the Department in writing within a reasonable time, any information that the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Department copies of any records required to be kept by the permit.

   b. Upon cause shown by the permittee the records, reports, or information, or a particular portion
thereof, claimed by the permittee to be confidential shall be submitted to the Department in accordance with the requirements of Article XXI, §2101.07.d.4. Information submitted to the Department under a claim of confidentiality, shall be available to the US EPA and the PADEP upon request and without restriction. Upon request of the permittee the confidential information may be submitted to the USEPA and PADEP directly. Emission data or any portions of any draft, proposed, or issued permits shall not be considered confidential.

10. Modification of Section 112(b) Pollutants which are VOCs or PM10 (§2103.12.f.7)

Except where precluded under the Clean Air Act or federal regulations promulgated under the Clean Air Act, if this permit limits the emissions of VOCs or PM$_{10}$ but does not limit the emissions of any hazardous air pollutants, the mixture of hazardous air pollutants which are VOCs or PM$_{10}$ can be modified so long as no permit emission limitations are violated. A log of all mixtures and changes shall be kept and reported to the Department with the next report required after each change.

11. Right to Access (§2103.12.h.2)

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized Department and other federal, state, county, and local government representatives to:

a. Enter upon the permittee's premises where a permitted source is located or an emissions-related activity is conducted, or where records are or should be kept under the conditions of the permit;

b. Have access to, copy and remove, at reasonable times, any records that must be kept under the conditions of the permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. As authorized by either Article XXI or the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements.

12. Certification of Compliance (§2103.12.h.5, §2103.22.i.1)

a. The permittee shall submit on an annual basis, certification of compliance with all terms and conditions contained in this permit, including emission limitations, standards, or work practices. The certification of compliance shall be made consistent with General Condition 4 above and shall include the following information at a minimum:

1) The identification of each term or condition of the permit that is the basis of the certification;

2) The compliance status;

3) Whether any noncompliance was continuous or intermittent;

4) The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with the provisions of this permit; and

5) Such other facts as the Department may require to determine the compliance status of the source.

b. All certifications of compliance must be submitted to the Department by March 31 of each year for the time period beginning January 1 of the previous year and ending December 31 of the previous year.

c. The permittee shall submit all compliance certifications to the Department. Compliance
13. Record Keeping Requirements (§2103.12.j.1)

a. The permittee shall maintain records of required monitoring information that include the following:

1) The date, place as defined in the permit, and time of sampling or measurements;
2) The date(s) analyses were performed;
3) The company or entity that performed the analyses;
4) The analytical techniques or methods used;
5) The results of such analyses; and
6) The operating parameters existing at the time of sampling or measurement.

b. The permittee shall maintain and make available to the Department, upon request, records, including computerized records that may be necessary to comply with the reporting and emission statements in Article XXI §2108.01.e. Such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions.

14. Retention of Records (§2103.12.j.2)

The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by 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 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 January 31 of each year for the time period beginning July 1 and ending December 31 of the previous year.
3) The next semiannual report shall be due January 31, 2017 for the time period beginning on the issuance date of this permit through December 31, 2016.
e. Quarterly reports required by this permit shall be submitted to the Department as follows:

1) One quarterly report is due by April 30 of each year for the time period beginning January 1 and ending March 31.
2) One quarterly report is due by July 31 of each year for the time period beginning April 1 and ending June 30.
3) One quarterly report is due by October 31 of each year for the time period beginning July 1 and ending September 30.
4) One quarterly report is due by January 31 of each year for the time period beginning October 1 and ending December 31 of the previous year.
5) The next quarterly report shall be due January 31, 2017 for the time period beginning on the issuance date of this permit through December 31, 2016.

f. The permittee may submit reports electronically to agreports@alleghenycounty.us. Certification by the responsible official in accordance with condition III.4 above shall be provided separately via hand copy.


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

17. Existing Source Reactivations (§2103.13.d)

The permittee shall not reactivate any source that has been out of operation or production for a period of one year or more unless the permittee has submitted a reactivation plan request to, and received a written reactivation plan approval from, the Department. Existing source reactivations shall meet all requirements of Article XXI §2103.13.d.


An administrative permit amendment may be made consistent with the procedures of Article XXI §2103.14.b and §2103.24.b. Administrative permit amendments are not authorized for any amendment precluded by the Clean Air Act or the regulations thereunder.


Sources may apply for revisions and minor permit modifications on an expedited basis in accordance with Article XXI §2103.14.c and §2103.24.a.


Significant permit modifications shall meet all requirements of the applicable subparts of Article XXI, Part C, including those for applications, fees, public participation, review by affected States, and review by EPA, as they apply to permit issuance and permit renewal. The approval of a significant permit modification, if the entire permit has been reopened for review, shall commence a new full five (5) year permit term. The Department shall take final action on all such permits within nine (9) months following receipt of a complete application.
21. **Duty to Comply** (§2103.12.f.1, §2103.22.g)

The permittee shall comply with all permit conditions and all other applicable requirements at all times. Any permit noncompliance constitutes a violation of the Clean Air Act, the Air Pollution Control Act, and Article XXI and is grounds for any and all enforcement action, including, but not limited to, permit termination, revocation and reissuance, or modification, and denial of a permit renewal application.

22. **Renewals** (§2103.13.b., §2103.23.a)

Renewal of this permit is subject to the same fees and procedural requirements, including those for public participation and affected State and EPA review that apply to initial permit issuance. The application for renewal shall be submitted at least six (6) months but not more than eighteen (18) months prior to expiration of this permit. The application shall also include submission of a supplemental compliance review as required by Article XXI §2102.01.

23. **Reopenings for Cause** (§2103.15, §2103.25.a, §2103.12.f.3)

   a. This permit shall be reopened and reissued under any of the following circumstances:

      1) Additional requirements under the Clean Air Act become applicable to a major source with a remaining permit term of three (3) or more years. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended solely due to the failure of the Department to act on a permit renewal application in a timely fashion.

      2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into this permit.

      3) The Department or EPA determines that this permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

      4) The Administrator or the Department determines that this permit must be reissued or revoked to assure compliance with the applicable requirements.

   b. This permit may be modified; revoked, reopened, and reissued; or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in this permit.

24. **Reopenings for Cause by the EPA** (§2103.25.b)

This permit may be modified, reopened and reissued, revoked or terminated for cause by the EPA in accordance with procedures specified in Article XXI §2103.25.b.

25. **Annual Operating Permit Administration Fee** (§2103.40)
In each year during the term of this permit, on or before the last day of the month in which the application for this permit was submitted, the permittee shall submit to the Department, in addition to any other applicable administration fees, an Annual Operating Permit Administration Fee in accordance with §2103.40. by check or money order payable to the “Allegheny County Air Pollution Control Fund” in the amount specified in the fee schedule applicable at that time.

26. **Annual Major Source Emissions Fees Requirements** (§2103.41)

No later than September 1 of each year, the permittee shall pay an annual emission fee in accordance with Article XXI §2103.41 for each ton of a regulated pollutant (except for carbon monoxide) actually emitted from the source. The permittee shall not be required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant. The emission fee shall be increased in each year after 1995 by the percentage, if any, by which the Consumer Price Index for the most recent calendar year exceeds the Consumer Price Index for the previous calendar year.

27. **Other Requirements not Affected** (§2104.08, §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 the odor emission standards under Article XXI §2104.04, any applicable NSPSs, NESHAPs, MACTs, or Generally Achievable Control Technology (GACT) standards now or hereafter established by the EPA, and any applicable requirements of BACT or LAER as provided by Article XXI, any condition contained in any applicable Installation or Operating Permit and/or any additional or more stringent requirements contained in an order issued to such person pursuant to Article XXI Part I.

28. **Termination of Operation** (§2108.01.a)

In the event that operation of any source of air contaminants is permanently terminated, the person responsible for such source shall so report, in writing, to the Department within 60 days of such termination.

29. **Emissions Inventory Statements** (§2108.01.e & g)

a. Emissions inventory statements in accordance with Article XXI §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.

30. **Tests by the Department** (§2108.02.d)

Notwithstanding any tests conducted pursuant to Article XXI §2108.02, 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 person responsible for such source or equipment shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.
31. 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.

32. Enforcement and Emergency Orders (§2109.03, §2109.05)

a. The person responsible for this source shall be subject to any and all enforcement and emergency orders issued to it by the Department in accordance with Article XXI §2109.03, §2109.04 and §2109.05

b. Upon request, any person aggrieved by an Enforcement Order or Emergency Order shall be granted a hearing as provided by Article XXI §2109.03.d; provided, however, that an Emergency Order shall continue in full force and effect notwithstanding the pendency of any and such appeal

c. Failure to comply with an Enforcement Order or immediately comply with an Emergency Order shall be a violation of this permit, thus giving rise to the remedies provided by Article XXI §2109.02.

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

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

34. 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 or any unsuccessful petitioner to the Administrator under Article XXI Part C, Subpart 2, shall have the right to appeal the action to the Director in accordance with the applicable County regulations and ordinances.

35. Risk Management (§2104.08, 40 CFR Part 68)

Should this stationary source, as defined in 40 CFR Part 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in Part 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by General Condition III.12 above.

36. Permit Shield (§2103.22)

a. The permittee’s compliance with the conditions of this permit shall be deemed compliance with all major source applicable requirements as of the date of permit issuance, provided that:

1) Such major source applicable requirements are included and are specifically identified in the permit; or
2) The Department, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

b. Nothing in Article XXI §2103.22.e or the Title V Permit shall alter or affect the following:

1) The provisions of Section 303 of the Clean Air Act and the provisions of Article XXI regarding emergency orders, including the authority of the Administrator and the Department under such provisions;
2) The liability of any person who owns, operates, or allows to be operated, a source in violation of any major source applicable requirements prior to or at the time of permit issuance;
3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; or
4) The ability of the EPA or the County to obtain information from the permittee pursuant to Section 114 of the Clean Air Act, the provisions of Article XXI and State law.

c. Unless precluded by the Clean Air Act or regulations therein, final action by the Department on administrative amendments, minor and significant permit modifications, and operational flexibility changes shall be covered by the permit shield provided such amendments, modifications and changes meet the relevant requirements of Article XXI.

d. The permit shield authorized under Article XXI §2103.22 is in effect for the permit terms and conditions as identified in this permit.

37. **Circumvention (§2101.14)**

For purposes of determining compliance with the provisions of this permit and Article XXI, no credit shall be given to any person for any device or technique, including but not limited to the operation of any source with unnecessary amounts of air, the combining of separate sources except as specifically permitted by Article XXI and the Department, the use of stacks exceeding Good Engineering Practice height as defined by regulations promulgated by the US EPA at 40 CFR §§51.100 and 51.110 and Subpart I, and other dispersion techniques, which without reducing the amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise violate the provisions of this Article; except that, for purposes of determining compliance with Article §2104.04 concerning odors, credit for such devices or techniques, except for the use of a masking agent, may be given.

38. **Duty to Supplement and Correct Relevant Facts (§2103.12.d.2)**

a. The permittee shall provide additional information as necessary to address the requirements that become applicable to the source after the date it files a complete application but prior to the Department taking action on the permit application.

b. The permittee shall provide supplementary fact or corrected information upon becoming aware that incorrect information has been submitted or relevant facts were not submitted.

c. Except as otherwise required by this permit and Article XXI, the Clean Air Act, or the regulations thereunder, the permittee shall submit additional information as necessary to address changes occurring at the source after the date it files a complete application but prior to the Department taking action on the permit application.
d. The applicant shall submit information requested by the Department which is reasonably necessary to evaluate the permit application.

39. Effect (§2102.03.g.)
   a. Except as specifically otherwise provided under Article XXI, Part C, issuance of a permit pursuant to Article XXI Part B or Part C shall not in any manner relieve any person of the duty to fully comply with the requirements of this permit, 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 this permit or Article XXI, whether occurring before or after the issuance of such permit. Further, except as specifically otherwise provided under Article XXI Part C the issuance of a 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 this permit or Article XXI.

40. Installation Permits (§2102.04.a.1.)
   
   It shall be a violation of this permit giving rise to the remedies set forth in Article XXI Part I for any person to install, modify, replace, reconstruct, or reactivate any source or air pollution control equipment which would require an installation permit or permit modification in accordance with Article XXI Part B or Part C.

PERMIT SHIELD IN EFFECT
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. 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) The 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.
8. **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.

9. **Emissions Inventory Statements (§2108.01.e)**

The permittee shall submit to the Department a written emissions inventory statement, in accordance with §2108.01.e, showing the actual emissions of all regulated air pollutants from such source(s) during each calendar year and all supporting and identifying information deemed necessary by the Department.

10. **Orders (§2108.01.f)**

In addition to meeting the requirements of General Condition III.28 and Site Level Conditions IV.7 through IV.9 above, inclusive, and IV.16 below, 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.

11. **Violations (§2108.01.g)**

The failure to submit any report or update thereof required by General Condition III.28 and Site Level Conditions IV.7 through IV.10 above, inclusive, and IV.16 below 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. **Emissions Testing (§2108.02)**

a. On or before December 31, 1981, and at two-year intervals thereafter, any person who operates, or allows to be operated, any piece of equipment or process which has an allowable emission rate, of 100 or more tons per year of particulate matter, sulfur oxides or volatile organic compounds shall conduct, or cause to be conducted, for such equipment or process such emissions tests as are necessary to demonstrate compliance with the applicable emission limitation(s) of this permit and shall submit the results of such tests to the Department in writing. Emissions testing conducted pursuant to this section shall comply with all applicable requirements of Article XXI §2108.02.e.

b. **Orders.** In addition to meeting the requirements of Site Level Condition IV.12.a above, the person responsible for any source shall, upon order by the Department, conduct, or cause to be conducted, such emissions tests as specified by the Department within such reasonable time as is specified by the Department. Test results shall be submitted in writing to the Department within 20 days after completion of the tests, unless a different period is specified in the Department's order. Emissions
testing shall comply with all applicable requirements of Article XXI §2108.02.e.

c. **Tests by the Department.** Notwithstanding any tests conducted pursuant to Site Level Conditions IV.12.a and IV.12.b above, 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 person responsible for such source or equipment shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.

d. **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.

e. 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.

f. **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.

13. **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.

14. **Asbestos Abatement** (§2105.62, §2105.63, 40 CFR 61.145 & 61.150)

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. In the event of demolition or renovation of asbestos, the permittee shall comply with all applicable provisions of 40 CFR 61.145 and 40 CFR 61.150.
15. Protection of Stratospheric Ozone (40 CFR Part 82)

a. Permittee shall comply with the standards for labeling of products using ozone-depleting substances pursuant to 40 CFR Part 82, Subpart E:

1) All containers in which a Class I or Class II substance is stored or transported, all products containing a Class I substance, and all products directly manufactured with a process that uses a Class I substance must bear the required warning statement if it is being introduced into interstate commerce pursuant to §82.106;

2) The placement of the required warning statement must comply with the requirements pursuant to §82.108;

3) The form of the label bearing the required warning statement must comply with the requirements pursuant to §82.110; and

4) No person may modify, remove or interfere with the required warning statement except as described in §82.112.

b. Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F:

1) Persons opening appliances for maintenance, service, repair or disposal must comply with the prohibitions and required practices pursuant to §82.154 and §82.156;

2) Equipment used during the maintenance, service, repair or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158;

3) Persons maintaining, servicing, repairing or disposing of appliances, must be certified by an approved technician certification program pursuant to §82.161;

4) Persons maintaining, servicing, repairing or disposing of appliances must certify to the Administrator of the U.S. Environmental Protection Agency pursuant to §82.162;

5) Persons disposing of small appliances, motor vehicle air conditioners (MVAC) and MVAC-like appliances, must comply with the record keeping requirements pursuant to §82.166;

6) Owners of commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156; and

7) Owners or operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

c. If the permittee manufactures, transforms, destroys, imports or exports a Class I or Class II substance, the permittee is subject to all the requirements as specified in 40 CFR Part 82, Subpart A (Production and Consumption Controls).

d. If the permittee performs a service on a motor vehicle that involves an ozone-depleting substance, refrigerant or regulated substitute substance in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B (Servicing of Motor Vehicle Air
Conditioners).

e. If the permittee has containers or products containing or manufactured with certain ozone-depleting substances, the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart E (The Labeling of Products Using Ozone-Depleting Substances).

f. If the permittee services, performs maintenance or repairs, or disposes of appliances that contain class I or class II refrigerants, the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart F (Recycling and Emissions Reduction).


g. The permittee may switch from any ozone-depleting substance to any alternative that is listed as acceptable in the Significant New Alternatives Policy (SNAP) program promulgated pursuant to 40 CFR Part 82, Subpart G.

h. If the permittee tests, services, maintains, repairs, or disposes of equipment that contains halons or uses such equipment during technician training, the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart H (Halon Emissions Reduction)

16. **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.16.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) The 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;

   i. 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

ii. Such other information as may be required by the Department.

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. **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.

   Notwithstanding any other provisions of this permit, the prohibitions of Site Level Condition IV.22 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.22.
23. **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 hoisting, venting, and collection of fugitive emissions.

24. **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.


The provisions of 40 CFR 63, Subpart DDDDD, which are incorporated by reference in ACHD Article XXI §2104.08.a, apply to the 4 boilers; HPH Batch Annealing Furnaces (31 individual furnaces); Open Coil Annealing Furnaces (16 furnaces); Continuous Annealing, and No.1 Continuous Galvanizing Galvaneal Furnace. The permittee shall comply with the emissions limitation, testing, monitoring, recordkeeping, reporting and workpractise standards. The facility shall submit an application to Department within 6 months of the compliance date January 31, 2016 to incorporate specific requirements from 40 CFR 63, Subpart DDDDD in accordance with §2103.25.a.1. [§2103.12.h.6; §2103.12.f.3; §2103.25.a.1; §63.7495.b.]

26. **SO₂ Compliance Monitoring (SO₂ SIP IP 0050-1008, Condition IV.25)**

a. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted as a fuel for or at any source 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. (§2105.21.h)

b. For the sources V.A, V.E, V.F, V.G, V.K V.L V.M and V.N, the permittee shall determine the H₂S grain loading and flow rate of the fuel as combusted. The permittee shall record the output of each system for measuring sulfur dioxide emissions discharged to the atmosphere

c. SO₂ emissions from Boilers No. 3 & 4 (aggregate) shall not exceed the limitations in Table V-L-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]
**TABLE IV-1**

SO₂ Emission Limitations for Boilers 3 & 4

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.21</td>
<td>9.30</td>
<td>35.96</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons/year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

27. The Continuous Terne Line (P014), and Galvaneneal Furnace (part of P012) have been removed from the permit. They are no longer in operation, and shall not be operated.

**PERMIT SHIELD IN EFFECT**
V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Process P001: 80-inch Hot Strip Mill

Process Description: 80” Hot Strip Mill Reheat Furnaces, Roughing and Finishing Mills
Facility ID: P001 – P005 and P016
Max. Design Rate: 140 mmBtu/hr maximum heat input, each reheat furnace
Capacity: 3,000,000 tons of sheets per year
Raw Materials: Steel Slabs, Natural Gas and Coke Oven Gas
Control Device: None

As identified above, the 80” Hot Strip Mill includes five reheat furnaces (P001 – P005) and the roughing and finishing mills (P016).

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in reheat furnaces No. 1 through No. 5. [§2103.12.h.5.D]

b. The permittee shall not operate or, allow to be operated reheat furnaces No. 1 through No. 5 such a manner that the emissions of particulate matter exceeds 7 pounds in any 60 minute period or 100 pounds in any 24-hour period [§2104.02.b]

c. The permittee shall not operate or, allow to be operated the scale breaking/roughing and finishing mill stands in such a manner that the emissions of particulate matter exceeds 7 pounds in any 60 minute period or 100 pounds in any 24-hour period [§2104.02.b]

d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in reheat furnaces No. 1 through No. 5, 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. [§2105.21.h.4]

e. The permittee shall operate the 80" Hot Strip Mill scale breaking/roughing and finishing mill stands with lubricating oil, which is an oil-water emulsion and does not exceed a maximum VOC content by weight, of 4%, at any time. [RACT Order No. 258; §2105.06; 25 PA Code §129.99]

f. Emissions from the Hot Strip Mill Reheat Furnaces No. 1 through No. 5 shall not exceed the emission limitations in Table V-A-1. [§2104.02; §2104.03; §2101.02.c.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Coke Oven Gas (lb/hr)</th>
<th>Natural Gas (lb/hr)</th>
<th>Annual Emission Limit (tons/year)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM-10</td>
<td>7.0</td>
<td>7.0</td>
<td>18.25</td>
</tr>
</tbody>
</table>

* A year is defined as any consecutive 12-month period.
g. SO₂ emissions from the HPH Annealing Furnaces (aggregate) shall not exceed the limitations in Table V-A-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]

**TABLE V-A-2**
SO₂ Emission Limitations for each Hot Strip Mill Reheat Furnace (Aggregate)

<table>
<thead>
<tr>
<th></th>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>108.63</td>
<td>118.75</td>
<td>475.80</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

** Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:

a. The permittee shall have sulfur dioxide (SO₂) emissions tests performed on the stacks of reheat furnaces No. 1 through No. 5 at least once every two years to demonstrate compliance with the mass emission limitations for the reheat furnaces No. 2 through No. 5 in condition V.A.1.g above. The test shall be conducted according to Method 6, 6A, 6B, or 6B specified in 40 CFR 60, Appendix A, and as approved by the Department. The permittee shall submit a stack test protocol to the Department for approval at least 45 days prior to the test dates. [SO₂ SIP IP 0050-1008, Condition V.A.2.a; §2108.02.b & .e]

b. The permittee shall perform emissions tests and evaluations for NOₓ, CO, and VOC on the stacks of reheat furnaces No. 1 through No. 5 to develop emission factors that can be applied to quantify NOₓ, CO, and VOC emissions. Testing for NOₓ, CO, and VOCs shall be conducted in accordance with approved EPA Methods in Appendix A of 40 CFR 60, Article XXI §2108.02, and as approved by the Department. Reports of the evaluation and stack testing results shall be submitted to the Department within 90 days of the date of the stack test. If testing results indicate emissions in excess of the thresholds identified in §2108.02.b, testing shall be conducted biennially for the applicable pollutant.

c. 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 12 entitled “Emissions Testing.” (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Condition IV.26.b above. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.A.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.A.3.a. However, if there is a change to the current operating scenario, these measurements will be re-evaluated.
scenario, the sulfur concentration will be taken at the Irvin Plant.  (§2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain the following records of the annual tune-up for the subject equipment:
      [RACT Order No. 258; 25 PA Code §129.100]
      1) The date of the annual tune-up;
      2) The name of the service company and/or individuals performing the annual tune-up;
      3) The operating rate or load after the annual tune-up; and
      4) The CO and NOx emission rate before and after the annual tune-up
   b. The permittee shall maintain hourly, monthly and 12 month rolling totals of the fuel type (COG & natural gas), and fuel usage and hourly H2S concentration expressed in grains per 100 dscf for each 80" Hot Strip Mill reheat furnace.  [§2103.12.h.5.B; §2103.12.j; SIP IP 0050-1008, Condition V.A.4.a; 25 PA Code §129.100]
   c. The permittee shall maintain sufficient documentation to demonstrate compliance with the VOC requirements in RACT Order No. 258 for the 80" Hot Strip Mill. Compliance with this RACT requirement may be demonstrated by documentation from all suppliers of oils for the 80" Hot Strip Mill that includes the VOC content of these oils.  [§2103.12.j, 25 PA Code §129.100]
   d. 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; 25 PA Code §129.100]

5. Reporting Requirements:
   a. The permittee shall provide semi-annual reports, as specified in Condition III.15 above, of the type and amount of each fuel combusted in the reheat furnaces required by Condition V.A.4.a.  [§2103.12.k]
   b. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported.  [§2103.12.k; §2103.12.j; SIP IP 0050-1008, Condition V.A.5.a]
   c. Reporting instances of non-compliance in accordance with Condition V.A.5.b above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate.  [§2103.12.k]

6. Work Practice Standards:
   a. The permittee shall perform an annual adjustment or "tune-up" on each furnace once every twelve (12) months, (hereafter referred to as "annual tune-up").  Such annual tune-up shall include:
      [RACT Order No. 258; 25 PA Code §129.99]
      1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
      2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total
emissions of NO\textsubscript{X}, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

None except as provided elsewhere.

*PERMIT SHIELD IN EFFECT*
B. **Process P002: 64” Continuous Coil HCl Pickle Line**

**Process Description:**
The pickle line consists of steel roll uncoilers, four (4) hydrochloric acid pickling tanks in series, a rinse tank, a dryer, a coiler and hydrochloric acid storage tanks.

**Facility ID:**
P002

**Max. Design Rate:**
1,047,174 tons of sheets per year

**Capacity:**
1,047,174 tons of sheets per year

**Raw Materials:**
Steel coils, HCl pickle liquor

**Control Device:**
HCl Scrubber

As identified above, Process SP023 consists of the following number and type of equipment: steel roll uncoilers, four hydrochloric acid pickling tanks in series, a dryer and a coiler.

1. **Restrictions - Installation Permits, Standards for Issuance, BACT**

   a. The permittee shall not operate or allow to be operated the 64” continuous coil HCl pickle line unless the four hydrochloric acid pickling tanks and the rinse tank, are equipped with an acid mist capture system that exhausts to a water wash packed tower scrubbing system. The collection and scrubbing system shall be properly maintained and operated, controlling hydrochloric acid emissions from the pickle line, according to the following specifications while the line is in operation: [Installation Permit No. 0050-I001b, Condition V.A.1.a, §2103.12.a.2.B and §2102.04.b.6]

   1) The acid mist capture system shall have a slight negative air flow into the system at all times and cover the acid and rinse tanks completely with minimum openings for the steel sheet inlet and outlet and associated piping.

   2) The water washed packed tower scrubber shall have the minimum scrubber makeup water and recirculating water flow rates determined by the average of the values recorded during the initial and/or subsequent scrubber emission testing as specified in Conditions V.B.2.a and V.B.2.b below.

   b. The permittee shall not cause or allow to be discharged into the atmosphere from the pickling line: [IP No. 0050-I001b, Condition V.A.1.b §63.1158(a); §2102.04.b.6]

   1) Any gases that contain HCl in a concentration in excess of 6 parts per million by volume (ppmv); and

   2) HCl at a mass emission rate that corresponds to a collection efficiency of less than 99 percent.

   c. The pickle line wet scrubber and HCl storage tank scrubber exhausts are subject to opacity requirements in Site Level Condition IV.2 above. [IP No. 0050-I001b, Condition V.A.1.c; §2104.01.a]

   d. The permittee of a hydrochloric acid storage vessel(s) shall provide and operate, except during loading and unloading of acid, a closed-vent system for each vessel. Loading and unloading shall be conducted either through enclosed lines or each point where the acid is exposed to the atmosphere shall be equipped with a local fume capture system, ventilated through an air pollution control device. The HCl fume scrubber shall be in place and operating according to the following specifications while in operation: [IP No. 0050-I001b, Condition V.A.1.d; §63.1159(b)]

   1) Packed tower HCl fume scrubber minimum scrubbing liquid flow rate of 11 gallons per minute.
2) Instrumentation shall be provided to measure the scrubbing liquid flow rate at any time, to within 5% of actual flow rate. Calibrations shall be performed semiannually.

e. The permittee shall comply with the operation and maintenance requirements prescribed under §63.6(e) of 40 CFR Part 63, Subpart A. [IP No. 0050-I001b, Condition V.A.1.f; §63.1160(b)(1)]

f. The permittee shall at no time, operate or allow to be operated, the tension leveler/scale breaker unless it is enclosed with all particulate emissions exhausted to the tension leveler/scale breaker dust collector. The dust collector shall be in place and operating, treating all particulate matter emissions from the tension leveler/scale breaker according to the following specifications while in operation. [Installation Permit No. 0050-I001b, Condition V.A.1.g and §2102.04.b.6]

1) Tension leveler/scale breaker dust collector – minimum and maximum pressure drop across the dust collector equal to 0.5 and 8.0 inches of water column, gauge.

g. Emissions from the Tension Leveler/Scale Breaker Dust Collector (SP023) shall not exceed the emission limitations in Table V-B-1 at any time. [IP No. 0050-I001b, Condition V.A.1.h; §2102.04.b.6; §2103.12.g]:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr</th>
<th>tons/yr 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.02</td>
<td>0.09</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.02</td>
<td>0.09</td>
</tr>
</tbody>
</table>

1 A year is defined as any 12 consecutive months.

h. Emissions from the 64” continuous coil pickle line shall not exceed the emission limitations in Table V-B-2 at any time. [IP No. 0050-I001b, Condition V.A.1.i; §63.1158(a); §2102.04.b.6; §2103.12.g]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Hourly Emission lbs/hr</th>
<th>Annual Emission tons/yr 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.41</td>
<td>1.79</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.41</td>
<td>1.79</td>
</tr>
<tr>
<td>HCl</td>
<td>0.41</td>
<td>1.79</td>
</tr>
</tbody>
</table>

1 A year is defined as any 12 consecutive months.

i. Compliance with the hydrochloric acid emission limitations for the 64” Continuous Coil HCl Pickle Line in Condition V.B.1.h above, shall be determined by initial and subsequent HCl emission testing annually as specified in Condition V.B.2.a below. Compliance with the particulate emission limitation for the wet scrubber shall be determined by assuming all hydrochloric acid emissions are PM-10 emissions. [Installation Permit No. 0050-I001b, Condition V.A.1.j and §2105.03]

2. Testing Requirements

a. The permittee shall conduct a performance test for each process or emission control device to
determine and demonstrate compliance with the applicable emission limitation according to the requirements in §63.7 of 40 CFR 63, Subpart A. [IP No. 0050-I001b, Condition V.A.2.a; §63.1161(a) and §2102.04.b.6]

1) Following approval of the site-specific test plan, the permittee shall conduct a performance test of the 64” continuous coil HCl pickle line wet scrubber control device to measure simultaneously the mass flows of HCl at the inlet and the outlet of the control device (to determine compliance with the applicable collection efficiency standard) and measure the concentration of HCl in gases exiting the process or the emission control device. [§63.1161(a)(1)]

2) Compliance with the applicable concentration standard and collection efficiency standard shall be determined by the average of three consecutive runs or by the average of any three of four consecutive runs. Each run shall be conducted under conditions representative of normal process operations. (§63.1161(a)(2))

3) Compliance with V.B.1.b above is achieved if the average collection efficiency as determined by the HCl mass flows at the control device inlet and outlet is greater than or equal to the applicable collection efficiency standard, and the average measured concentration of HCl exiting the emission control device is less than or equal to the applicable emission concentration standard. (§63.1161(a)(3))

b. During the performance test for the wet scrubber emission control device, the permittee using a wet scrubber to achieve compliance shall establish site-specific operating parameter values for the minimum scrubber makeup water flow rate and, for a scrubber that operates with recirculation, the minimum recirculation water flow rate. During the emission test, each operating parameter must be monitored continuously and recorded with sufficient frequency to establish a representative average value for that parameter, but no less frequently than once every 15 minutes. The permittee shall determine the operating parameter monitoring values as the averages of the values recorded during any of the runs for which results are used to establish the emission concentration and the collection efficiency per Condition V.B.1.b above. The permittee may conduct multiple performance tests to establish alternative compliant operating parameter values. Also, the permittee may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests. [IP No. 0050-I001b, Condition V.A.2.b; §63.1161(b)]

c. The permittee shall notify the Department in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, to allow the Department to review and approve the site-specific test plan required under Subpart A of 40 CFR 63.7(c) and, if requested by the Department, to have an observer present during the test. [IP No. 0050-I001b, Condition V.A.2.c; §63.1163(d)]

d. The permittee shall conduct performance tests to measure the HCl mass flows at the control device inlet and outlet and the concentration of HCl exiting the control device according to the procedures described in Condition V.B.2.a above. Performance tests to measure the HCl mass flows at the control device inlet and outlet shall be conducted at least once every five years. Performance tests to measure the concentration of HCl exiting the control device shall be conducted either annually or according to an alternative schedule that is approved by the Department, but no less frequently than every 2 1/2 years or twice per title V permit term. If any performance test shows that the HCl emission limitation is being exceeded, then the permittee is in violation of the emission limit. [Installation Permit No. 0050-I001b, Condition V.A.2.d; §63.1162(a) and §2108.02.b]
e. The following test methods in Appendix A of 40 CFR Part 60 shall be used to determine compliance with Condition V.B.1.b above: [IP No. 0050-I001b, Condition V.A.2.e §63.1161(d)]

1) Method 1, to determine the number and location of sampling points, with the exception that no traverse point shall be within one inch of the stack or duct wall;
2) Method 2, to determine gas velocity and volumetric flow rate;
3) Method 3, to determine the molecular weight of the stack gas;
4) Method 4, to determine the moisture content of the stack gas; and
5) Method 26A, "Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources -- Isokinetic Method," to determine the HCl mass flows at the inlet and outlet of a control device or the concentration of HCl discharged to the atmosphere. If compliance with a collection efficiency standard is being demonstrated, inlet and outlet measurements shall be performed simultaneously. The minimum sampling time for each run shall be 60 minutes and the minimum sample volume 0.85 dry standard cubic meters (30 dry standard cubic feet). The concentrations of HCl and Cl2 shall be calculated for each run as follows:

\[ C_{\text{HCl (ppmv)}} = 0.659 \times C_{\text{HCl (mg/dscm)}} \]

Where \( C_{\text{ppmv}} \) is concentration in ppmv and \( C_{\text{mg/dscm}} \) is concentration in milligrams per dry standard cubic meter as calculated by the procedure given in Method 26A.

f. The permittee may use equivalent alternative measurement methods to those specified in paragraph V.B.2.e above, subject to approval by the Administrator and the Department [IP No. 0050-I001b, Condition V.A.2.f; §63.1161(d)(2) and §63.1166(a)(2)]

g. The Department reserves the right to require emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with §2108.02. (IP No. 0050-I001b, Condition V.A.2.g; §2103.12.h.1)

3. Monitoring Requirements

a. The tension leveler/scale breaker dust collector shall be provided with instrumentation to continuously monitor the pressure drop across the dust collector, when treating particulate emissions from the tension leveler/scale breaker. [IP No. 0050-I001b, Condition V.A.3.a]

b. If the pressure drop exceeds the normal range as specified in V.B.1.f.1) above, the permittee shall initiate an investigation and implement corrective action. Operation outside the pressure drop range shall not be considered a deviation if corrective action is taken in 7 days. [IP No. 0050-I001b, Condition V.A.3.b; §2102.04.b.6]

c. The permittee shall inspect the tension leveler/scale breaker dust collector on a weekly basis to insure compliance with Conditions V.B.1.f and V.B.3.a above. Any excursions from these conditions shall be corrected as soon as possible. [IP No. 0050-I001b, Condition V.A.3.c; §2102.04.b.6]

d. The water wash packed tower scrubber shall be provided with instrumentation that shall monitor the pressure drop across the scrubber once per shift. [IP No. 0050-I001b, Condition V.A.3.d; §63.1160(b)(2)(i) and §2102.04.b.6]

e. The permittee shall install, operate, and maintain systems for the measurement and recording of the scrubber makeup water flow rate, and recirculation water flow rate. These flow rates must be
monitored continuously and recorded at least once per shift while the scrubber is operating. Operation of the wet scrubber with excursions of scrubber makeup water flow rate and recirculation water flow rate less than the minimum values established during the performance test or tests will require initiation of corrective action as specified by the maintenance requirements in V.B.6.a below. [IP No. 0050-I001b, Condition V.A.3.e; §63.1162(a)(2)]

f. Failure to record each of the operating parameters listed in paragraph V.B.3.e above is a violation of the monitoring requirements of this permit. [IP No. 0050-I001b, Condition V.A.3.f; §63.1162(a)(4)]

g. Each monitoring device specified in paragraphs V.B.3.d and V.B.3.e above shall be certified by the manufacturer to be accurate to within 5 percent and shall be calibrated in accordance with the manufacturer's instructions but not less frequently than once per year. [IP No. 0050-I001b, Condition V.A.3.g; §63.1162(a)(5)]

h. The permittee may develop and implement alternative monitoring requirements subject to approval by the Department and the Administrator. [IP No. 0050-I001b, Condition V.A.3.h; §63.1162(a)(6)]

i. The permittee shall inspect each hydrochloric acid storage vessel semiannually to determine that the closed-vent system and the air pollution control device are installed and operating when required. [IP No. 0050-I001b, Condition V.A.3.i; §63.1162(c)]

4. Record Keeping Requirements

a. The results of inspections required by Condition V.B.3.c above, and the differential pressure drop across the tension leveler/scale breaker dust collector, shall be recorded weekly. Episodes of noncompliance with Conditions V.B.1.f and V.B.3.a above and corrective action taken shall be recorded upon occurrence. All records shall be kept on a monthly basis. [IP No. 0050-I001b, Condition V.A.4.a; §2102.04.b.6]

b. The results of inspections required by Condition V.B.3.i above shall be recorded upon each occurrence. Episodes of noncompliance with Conditions V.B.1.d above and corrective action taken shall be recorded upon occurrence. All records shall be kept on a semiannual basis. [IP No. 0050-I001b, Condition V.A.4.b; §2102.04.b.6]

c. The permittee shall maintain a record of each inspection, including each item identified in paragraph V.B.6.a.4) below, that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other corrective action taken. [IP No. 0050-I001b, Condition V.A.4.c; §63.1160(b)(2)(vii)]

d. As required by §63.10(b)(2), the permittee shall maintain records for 5 years from the date of each record of: [IP No. 0050-I001b, Condition V.A.4.d; §63.1165(a)]

1) The occurrence and duration of each startup, shutdown, or malfunction of operation (i.e., process equipment);
2) The occurrence and duration of each malfunction of the air pollution control equipment;
3) All maintenance performed on the air pollution control equipment;
4) Actions taken during periods of startup, shutdown, and malfunction and the dates of such actions (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) when these actions are different from the procedures specified in the startup, shutdown, and malfunction plan;
5) All information necessary to demonstrate conformance with the startup, shutdown, and
malfunction plan when all actions taken during periods of startup, shutdown, and malfunction (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. This information can be recorded in a checklist or similar form [see 40 CFR 63.10(b)(2)(v)];
6) All required measurements needed to demonstrate compliance with the standard and to support data that the permittee is required to report, including, but not limited to, performance test measurements (including initial and any subsequent performance tests) and measurements as may be necessary to determine the conditions of the initial test or subsequent tests;
7) All results of initial or subsequent performance tests;
8) All documentation supporting initial notifications and notifications of compliance status required by 40 CFR 63.9; and
9) Records of any applicability determination, including supporting analyses.

e. In addition to the general records required by paragraph V.B.4.d above, the permittee shall maintain records for 5 years from the date of each record of: [IP No. 0050-I001b, Condition V.A.4.e; §63.1165(b)(1); §2103.12.j]
1) Scrubber makeup water flow rate and recirculation water flow rate;
2) Calibration and manufacturer certification that monitoring devices are accurate to within 5 percent; and
3) Each maintenance inspection and repair, replacement, or other corrective action.
f. The permittee shall record the production and hours of operation of the 64” continuous coil HCl pickle line on a daily basis, and the monthly throughput of HCl for each storage tank. [IP No. 0050-I001b, Condition V.A.4.f; §2103.12.j]
g. The pressure drop across the scrubber shall be recorded at least once daily and during the initial and/or subsequent scrubber emission testing. (IP No. 0050-I001b, Condition V.A.1.a.3; §2102.04.b.6; §2103.12.j]
h. The permittee shall keep the written operation and maintenance plan on record after it is developed to be made available for inspection, upon request, by the Department for the life of the affected source or until the source is no longer subject to these provisions. In addition, if the operation and maintenance plan is revised, the permittee shall keep previous (i.e., superseded) versions of the plan on record to be made available for inspection by the Department for a period of 5 years after each revision to the plan. [IP No. 0050-I001b, Condition V.A.4.g; §63.1165(b)(3)]
i. Records for the most recent 2 years of operation must be maintained on site. Records for the previous 3 years may be maintained off site. [IP No. 0050-I001b, Condition V.A.4.h; §63.1165(c)]

5. Reporting Requirements

a. The permittee shall submit a notification of compliance status as required by 40 CFR 63.9(h). [IP No. 0050-I001b, Condition V.A.5.a; §63.1163(e)]
b. The permittee shall report the results of any performance test required in paragraph V.B.2.a and V.B.2.d above. [IP No. 0050-I001b, Condition V.A.5.b; §63.1164(a)]
c. As required by 40 CFR §63.10(d)(5)(i), if actions taken by the permittee during a startup, shutdown, or malfunction of the 64” continuous coil pickle line (including actions taken to correct a malfunction) are consistent with the procedures specified in the startup, shutdown, and malfunction
plan, the permittee shall state such information in a semiannual report. The report, to be certified by the permittee or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half. [IP No. 0050-I001b, Condition V.A.5.c; §63.1164(c)(2)]

d. Any time an action taken by the permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures in the startup, shutdown, and malfunction plan, the permittee shall comply with all requirements of 40 CFR 63.10(d)(5)(ii). [IP No. 0050-I001b, Condition V.A.5.d; §63.1164(c)(3)]

e. Reporting instances of non-compliance in accordance with condition V.B.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. (IP No. 0050-I001b, Condition V.A.5.e; §2103.12.k.1)

6. **Work Practice Standard** (§2102.04.b.6)

   a. In addition to the requirements specified in paragraph V.B.1.e above, the permittee shall prepare an operation and maintenance plan for the 64” continuous coil HCl pickle line scrubber emission control devices. The plan shall be submitted to the Department for approval. The plan must be consistent with good maintenance practices and, for a scrubber emission control device, must at a minimum: [IP No. 0050-I001b, Condition V.A.6.a; §63.1160(b)(2) and §2102.04.b.6]

      1) Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;
      2) Require the manufacturer's recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system;
      3) Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;
      4) Require an inspection of each scrubber at intervals of no less than 3 months with:

         a) Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;
         b) Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;
         c) Repair or replacement of droplet eliminator elements as needed;
         d) Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and
         e) Adjustment of damper settings for consistency with the required air flow.

      5) If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Department may be used.

      6) The permittee shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirements of this permit.

   b. The permittee shall operate and maintain the 64” continuous coil HCl pickle line and the wet scrubber emission control device, in a manner consistent with good air pollution control practices for minimizing emissions at least to the level required by paragraph V.B.1.b above at all times, including during any period of startup, shutdown, or malfunction. Malfunctions must be corrected as soon as practicable after their occurrence in accordance with the startup, shutdown, and
malfunction plan specified in paragraph V.B.6.c below. [IP No. 0050-I001b, Condition V.A.6.b; §63.1164(c)]

c. As required by §63.6(e)(3) of 40 CFR Part 63, Subpart A, the permittee shall develop and implement a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the 64” continuous coil HCl pickle line and the wet scrubber emission control device during periods of startup, shutdown, or malfunction, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with the emission limitations in paragraph V.B.1.b above. [IP No. 0050-I001b, Condition V.A.6.c; §63.1164(c)(1)]

7. Additional Requirements

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
C. **Process P007: 84” Continuous Pickle Line**

**Process Description:** The pickle line consists of steel roll uncoilers, 4 hydrochloric acid pickling tanks in series, a rinse tank, a dryer and a coiler.

**Facility ID:** P007  
**Max. Design Rate:** 1,576,800 tons of sheet per year  
**Capacity:** 1,576,800 tons of sheet per year  
**Raw Materials:** Steel coils, HCl pickle liquor  
**Control Device:** HCl Scrubber

As identified above, Process P007 consists of the following number and type of equipment: steel roll uncoilers, four hydrochloric acid pickling tanks in series, a dryer and a coiler.

1. **Restrictions: - Installation Permits, Standards for Issuance, BACT**
   
a. The permittee shall not operate or allow to be operated the 84” continuous coil HCl pickle line unless the four hydrochloric acid pickling tanks and the rinse tank are equipped with an acid mist capture system that exhausts to a water wash scrubbing system. The collection and scrubbing system shall be properly maintained and operated, controlling hydrochloric acid emissions from the pickle line. [§2102.04.b.5]

b. The permittee shall not cause or allow to be discharged into the atmosphere from the 84” continuous pickling line scrubber: [§63.1157(a)]
   
   1) Any gases that contain HCl in a concentration in excess of 18 parts per million by volume (ppmv); or  
   2) HCl at a mass emission rate that corresponds to a collection efficiency of less than 97 percent.

c. The pickle line wet scrubber exhaust is subject to the opacity requirements in Site Level Condition IV.2. [§2104.01.a]

d. The permittee shall comply with the operation and maintenance requirements prescribed under paragraph 63.6(e) of 40 CFR Part 63, Subpart A. [§63.1160(b)(1)]

e. Emissions from the 84” Continuous Coil HCl Pickle Line shall not exceed the emission limitations in Table V-C at any time. [§63.1157(a)(1) and §2102.04.b.5]:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Hourly Emission Limit lbs/hr</th>
<th>Annual Emission Limit tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCl</td>
<td>2.9</td>
<td>12.55</td>
</tr>
</tbody>
</table>

   1 A year is defined as any 12 consecutive months.

2. **Testing Requirements:**

a. The permittee shall conduct a performance test for each process or emission control device to determine and demonstrate compliance with the emission limitation in Condition V.C.1.b above, according to the requirements in §63.7 of 40 CFR Part 63, Subpart A. The testing shall be completed as follows: [§63.1161(a)]

   1) Following approval of the site-specific test plan, the permittee shall conduct a performance test
of the 84” continuous coil HCl pickle line wet scrubber control device to either measure simultaneously the mass flows of HCl at the inlet and the outlet of the control device (to determine compliance with the collection efficiency standard of 97 percent) or measure the concentration of HCl in gases exiting the process or the emission control device (to determine compliance with the emission concentration standard of 18 ppmv). [§63.1161(a)(1)]

2) Compliance with the applicable concentration standard or collection efficiency standard shall be determined by the average of three consecutive runs or by the average of any three of four consecutive runs. Each run shall be conducted under conditions representative of normal process operations. [§63.1161(a)(2)]

3) Compliance is achieved if either the average collection efficiency as determined by the HCl mass flows at the control device inlet and outlet is greater than or equal to the applicable collection efficiency standard, or the average measured concentration of HCl exiting the emission control device is less than or equal to the applicable emission concentration standard. [§63.1161(a)(3)]

b. During the performance test for the wet scrubber emission control device, the permittee using a wet scrubber to achieve compliance shall establish site-specific operating parameter values for the minimum scrubber makeup water flow rate and, for a scrubber that operates with recirculation, the minimum recirculation water flow rate. During the emission test, each operating parameter must be monitored continuously and recorded with sufficient frequency to establish a representative average value for that parameter, but no less frequently than once every 15 minutes. The permittee shall determine the operating parameter monitoring values as the averages of the values recorded during any of the runs for which results are used to establish the emission concentration and the collection efficiency per Condition V.C.1.b above. The permittee may conduct multiple performance tests to establish alternative compliant operating parameter values. Also, the permittee may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests. [§63.1161(b)]

c. The permittee shall notify the Department in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, to allow the Department to review and approve the site-specific test plan required under Subpart A of 40 CFR 63.7(c) and, if requested by the Department, to have an observer present during the test. [§63.1163(d)]

d. The permittee shall conduct performance tests to measure the HCl mass flows at the control device inlet and outlet or the concentration of HCl exiting the control device according to the procedures described in Condition V.B.2.a above. Performance tests shall be conducted either annually or according to an alternative schedule that is approved by the Department, but no less frequently than every 2 1/2 years or twice per title V permit term. If any performance test shows that the HCl emission limitation is being exceeded, then the permittee is in violation of the emission limit. [§63.1162(a) and §2108.02.b]

e. The following test methods in Appendix A of 40 CFR Part 60 shall be used to determine compliance with Condition V.C.1.b above: [§63.1161(d)]

1) Method 1, to determine the number and location of sampling points, with the exception that no traverse point shall be within one inch of the stack or duct wall;
2) Method 2, to determine gas velocity and volumetric flow rate;
3) Method 3, to determine the molecular weight of the stack gas;
4) Method 4, to determine the moisture content of the stack gas; and
5) Method 26A, "Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources -- Isokinetic Method," to determine the HCl mass flows at the inlet and outlet of a control device or the concentration of HCl discharged to the atmosphere, and also to determine the concentration of Cl2 discharged to the atmosphere from acid regeneration plants. If compliance with a collection efficiency standard is being demonstrated, inlet and outlet measurements shall be performed simultaneously. The minimum sampling time for each run shall be 60 minutes and the minimum sample volume 0.85 dry standard cubic meters (30 dry standard cubic feet). The concentrations of HCl and Cl2 shall be calculated for each run as follows:

\[ C_{HCl}(\text{ppmv}) = 0.659 \times C_{HCl}(\text{mg/dscm}), \]

where \( C(\text{ppmv}) \) is concentration in ppmv and \( C(\text{mg/dscm}) \) is concentration in milligrams per dry standard cubic meter as calculated by the procedure given in Method 26A.

f. The permittee may use equivalent alternative measurement methods to those specified in paragraph V.C.2.c above, subject to approval by the Administrator and the Department [§63.1161(d)(2) and §63.1166(a)(2)]

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

3. Monitoring Requirements:

a. The wet scrubber shall be provided with instrumentation that shall monitor the pressure drop across the scrubber at least once per shift. [§63.1160(b)(2) and §2103.12j]

b. The permittee shall install, operate, and maintain systems for the measurement and recording of the scrubber makeup water flow rate and, if required, recirculation water flow rate. These flow rates must be monitored continuously and recorded at least once per shift while the scrubber is operating. Operation of the wet scrubber with excursions of scrubber makeup water flow rate and recirculation water flow rate less than the minimum values established during the performance test or tests will require initiation of corrective action as specified by the maintenance requirements in V.C.6.a below. [§63.1162(a)(2)]

c. Failure to record each of the operating parameters listed in paragraph V.C.3.b above is a violation of the monitoring requirements. [§63.1162(a)(4)]

d. Each monitoring device specified in paragraphs V.C.3.a and V.C.3.b above shall be certified by the manufacturer to be accurate to within 5 percent and shall be calibrated in accordance with the manufacturer's instructions but not less frequently than once per year. [§63.1162(a)(5)]

e. The permittee may develop and implement alternative monitoring requirements subject to approval by the Administrator and the Department. [§63.1162(a)(6)]

4. Record Keeping Requirements:

a. The permittee shall maintain a record of each inspection, including each item identified in paragraph V.C.6.a.4) below, that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other
corrective action taken, and the date of the repair, replacement, or other corrective action taken. [63.1160(b)(2)(vii)]

b. As required by §63.10(b)(2), the permittee shall maintain records for 5 years from the date of each record of: [§63.1165(a)]

1) The occurrence and duration of each startup, shutdown, or malfunction of operation (i.e., process equipment);
2) The occurrence and duration of each malfunction of the air pollution control equipment;
3) All maintenance performed on the air pollution control equipment;
4) Actions taken during periods of startup, shutdown, and malfunction and the dates of such actions (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) when these actions are different from the procedures specified in the startup, shutdown, and malfunction plan;
5) All information necessary to demonstrate conformance with the startup, shutdown, and malfunction plan when all actions taken during periods of startup, shutdown, and malfunction (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. This information can be recorded in a checklist or similar form [see 40 CFR 63.10(b)(2)(v)];
6) All required measurements needed to demonstrate compliance with the standard and to support data that the permittee is required to report, including, but not limited to, performance test measurements (including initial and any subsequent performance tests) and measurements as may be necessary to determine the conditions of the initial test or subsequent tests;
7) All results of initial or subsequent performance tests;
8) All documentation supporting initial notifications and notifications of compliance status required by 40 CFR 63.9; and
9) Records of any applicability determination, including supporting analyses.

c. In addition to the general records required by paragraph V.C.4.b above, the permittee shall maintain records for 5 years from the date of each record of: [§63.1165(b)(1)]

1) Scrubber makeup water flow rate and recirculation water flow rate if a wet scrubber is used;
2) Calibration and manufacturer certification that monitoring devices are accurate to within 5 percent; and
3) Each maintenance inspection and repair, replacement, or other corrective action.

d. The permittee shall record the production and hours of operation of the 84” continuous coil HCl pickle line on a monthly basis. [§2103.12.j]

e. The permittee shall maintain records that document that compliance was demonstrated in accordance 40 CFR Part 63, Subpart CCC §63.1160(a)(1) [§2103.12.j]

f. The permittee shall keep the written operation and maintenance plan on record after it is developed to be made available for inspection, upon request, by the Department for the life of the affected source or until the source is no longer subject to these provisions. In addition, if the operation and maintenance plan is revised, the permittee shall keep previous (i.e., superseded) versions of the plan on record to be made available for inspection by the Department for a period of 5 years after each revision to the plan. [§63.1165(b)(3)]

g. Records for the most recent 2 years of operation must be maintained on site. Records for the previous 3 years may be maintained off site. [§63.1165(c)]
5. Reporting Requirements:

a. The permittee shall submit a notification of compliance status as required by 40 CFR 63.9(h). [§63.1163(c)]

b. The permittee shall report the results of any performance test required in condition V.C.2.a. [§63.1164(a)]

c. As required by 40 CFR§63.10(d)(5)(i), if actions taken by the permittee during a startup, shutdown, or malfunction of the 84” continuous coil pickle line (including actions taken to correct a malfunction) are consistent with the procedures specified in the startup, shutdown, and malfunction plan, the permittee shall state such information in a semiannual report. The report, to be certified by the permittee or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half. [§63.1164(c)(2)]

d. Any time an action taken by the permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures in the startup, shutdown, and malfunction plan, the permittee shall comply with all requirements of 40 CFR 63.10(d)(5)(ii). [§63.1164(c)(3)]

e. Reporting instances of non-compliance in accordance with condition V.C.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. (§2103.12.k.1)

6. Work Practice Standard:

a. In addition to the requirements specified in condition V.C.1.d above, the permittee shall prepare an operation and maintenance plan for the 84” continuous coil pickle line scrubber emission control device. The plan shall be submitted to the Department for approval. The plan must be consistent with good maintenance practices and, must at a minimum: [63.1160(b)(2) and §2102.04.b.6]

1) Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;
2) Require the manufacturer’s recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system;
3) Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;
4) Require an inspection of each scrubber at intervals of no less than 3 months with:
   i. Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;
   ii. Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;
   iii. Repair or replacement of droplet eliminator elements as needed;
   iv. Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and
   v. Adjustment of damper settings for consistency with the required air flow.
5) If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Department may be used.
6) The permittee shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures
to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirements of this permit.

b. The permittee shall operate and maintain the 84” continuous coil HCl pickle line and the wet scrubber emission control device, in a manner consistent with good air pollution control practices for minimizing emissions at least to the level required by condition V.C.1.b above at all times, including during any period of startup, shutdown, or malfunction. Malfunctions must be corrected as soon as practicable after their occurrence in accordance with the startup, shutdown, and malfunction plan specified in paragraph V.C.6.c below. [§63.1164(c)]

c. As required by §63.6(e)(3) of 40 CFR 63, Subpart A, the permittee shall develop and implement a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the 84” continuous coil HCl pickle line and the wet scrubber emission control device during periods of startup, shutdown, or malfunction, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with the emission limitations in paragraph V.C.1.b above. [§63.1164(c)(1)]

7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
D. Process P008: No. 3 Five Stand Cold Reduction Mill

Process Description: Process P008 consists of steel roll uncoilers, cold reduction mill stands, steel roll hydraulic shear, and a roll coiler.

Facility ID: P008
Max. Design Rate: 3,767,676 tons of steel coils per year
Capacity: 2,500,000 tons of steel coils per year
Raw Materials: Steel Coils
Control Device: Cyclonic Mist Eliminator

As identified above, Process P008 consists of following types of equipment: steel roll uncoilers, cold reduction mill stands, steel coil hydraulic shear, and a roll coiler.

1. Restrictions - Installation Permits, Standards for Issuance, BACT

a. The permittee shall not operate or allow to be operated, the cold reduction mill unless the five mill stands are equipped with a capture system that exhausts to a mist eliminator control system. The collection and control system shall be properly maintained and operated, controlling oil mist emissions from the cold reduction mill, according to the following specifications while the line is in operation: [Installation Permit No. 0050-I002a, and §2102.04.b.6]

1) The capture system shall have a negative air flow into the system at all times and partially enclose the mill stands with openings for the steel sheet inlet and outlet and openings for observation and access to the rollers and steel.

2) The mist eliminator control system shall be comprised of five identical cyclone mist eliminators, in parallel with a design minimum combined air flow rate of 200,000 ACFM.

3) The North and South fans shall maintain an inlet static pressure that is no more negative than -8.0" w.c.

b. The permittee shall conduct cleaning of the cyclone mist eliminators specified in Condition V.D.1.a above once every four months. This cleaning will be conducted in such a way as to thoroughly remove all material or corrosion that could decrease the mist eliminator efficiencies. Notwithstanding the previous, cleaning shall be conducted immediately following any inspection of the mist eliminators as specified in Condition V.D.3.a below if warranted by the inspection findings or when a measured inlet pressure exceeds Condition V.D.1.a.3) above. [Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

c. The permittee shall not operate or allow to be operated, the cold reduction mill in such a manner that the production during any 12 consecutive months exceeds 2,500,000 tons of steel or the daily average hourly production rate exceeds 525 tons of steel per hour based on the number of hours of operation in a day. [Installation Permit No. 0050-I002a]

d. The permittee shall not operate the Cold Reduction Mill with a lubricating oil VOC content, by weight greater than 2% and a water-oil emulsion oil content, by volume greater than 7%, at any time. [Installation Permit No. 0050-I002a; RACT Order No. 258, §2105.06; 25 PA Code §129.99]
e. Emissions from the cold reduction mill shall not exceed the limitations in Table V-D-1 at any time: [Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

Table V-D-1 - No. 3 Five Stand Cold Reduction Mill Emission Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/ton steel rolled</th>
<th>lbs/hour</th>
<th>tons/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
<tr>
<td>Volatile Organic Compound</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
</tbody>
</table>

1A year is defined as any consecutive 12-month period

2. Testing Requirements:
   a. The permittee shall conduct emission testing for particulate matter on the cold reduction mill oil mist capture and control system in order to determine compliance with the emissions limitations of condition V.D.1.e above. Testing shall be at least once every 5 years thereafter. Such testing shall be performed according to EPA approved test methods No. 1, No. 2, No. 3, No. 4 and No. 5 as specified in 40 CFR 60, Appendix A and in accordance with Section §2108.02 of Article XXI, or as approved by the Department. [Installation Permit No. 0050-I002a, 2/12/04 and §2108.02.a.]
   b. The Department reserves the right to require emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. The permittee shall inspect the cold reduction mill capture system and control system specified in Condition V.D.1.a above to insure the proper operation and physical integrity of all collection and control equipment and verify negative air flow into the collection and control system daily to insure compliance with Condition V.D.1.a above. The permittee shall inspect one cyclone per week so that each cyclone is inspected a minimum of once every five weeks to insure that the cyclones are clean and free of all material or corrosion that could decrease the efficiencies of the cyclones. Notwithstanding the previous, inspections of all other cyclones shall be conducted immediately following the specified monthly single cyclone inspection if the cyclone is found to be nonfunctional, in a condition that would reduce the operating efficiency or if a measured inlet pressure exceeds Condition V.D.1.a.3) above. Any excursions from Condition V.D.1.a above shall be corrected as soon as possible. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.3 & §64.6]
   b. Instrumentation shall be provided that can directly measure the inlet pressure of each of the collection and control system exhaust fans to within 1/10" w.c. The inlet pressure shall be measured for each fan weekly and after any cleaning conducted on the cyclones. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.3 & §64.6]
4. **Record Keeping Requirements:**

   a. The permittee shall record the production and the hours of operation of the cold reduction mill on a daily basis. [Installation Permit No. 0050-I002a, 2/12/04 and §2103.12.j]

   b. The permittee shall record the type and VOC content of all rolling oils, the percent of rolling oil in the water-oil emulsion as applied and the amount of emulsion used for the cold reduction mill on a daily basis. In addition, all emission test data from tests required by Condition V.D.2.a above shall be retained at the facility as per Condition V.D.4.d below. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.9(b); §2103.12.j; 25 PA Code §129.100]

   c. The results of the inspections required by Condition V.D.3.a above shall be recorded weekly. The monitoring data specified Condition V.D.3.b above shall be recorded weekly and after every cyclone cleaning. Episodes of non-compliance with Conditions V.D.1.a, V.D.1.b or V.D.3.a above and corrective actions taken shall be recorded upon occurrence. All such records shall be summarized monthly. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.9(b); §2103.12.j]

   d. 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. [Installation Permit No. 0050-I002a, 2/12/04; §§2103.12.j.2; ; 25 PA Code §129.100]

5. **Reporting Requirements:**

   a. The permittee shall provide quarterly reports that contain monthly summaries of production, hours of operation, and maximum percent VOC content, by weight, of the rolling oil and the maximum percent, by weight, of the rolling oil in the water-oil emulsion. The due dates of these reports are prescribed in General Condition III.15.e above. [Installation Permit No. 0050-I002a, 2/12/04; §2103.12.k.1; 40 C.F.R. §64.9(a)]

   b. The permittee shall report the exhaust fans inlet pressures weekly measurements specified in Condition V.D.3.b above within thirty days of the end of each calendar half as required in General Condition III.15.d. §2103.12.k.1; 40 C.F.R. §64.9(a)]

   c. The permittee shall report all instances of non-compliance with Conditions V.D.1.a, V.D.1.b, V.D.1.c, V.D.1.d, V.D.1.e, V.D.3.a, and V.D.3.b above along with all corrective action taken to restore the subject equipment to compliance, to the Department every three months in accordance with General Condition III.15.e above. [§2103.12.k.1]

   d. Reporting instances of non-compliance in accordance with Condition V.D.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k.1]

6. **Work Practice Standard:**

   a. The permittee shall maintain and operate the cold rolling mill in accordance with good air pollution control practices, by performing regular maintenance as required by condition V.D.3, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258; 25 PA Code §129.99]
7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
E. Process P009: HPH Annealing Furnaces

Process Description: The HPH Annealing Process consists of 31 individual movable furnaces with 58 bases in one unit that treat coiled steel rolls. Each furnace is fired with coke oven gas enriched with natural gas and has a maximum heat input rating of 4.9 MMBtu/hr

<table>
<thead>
<tr>
<th>Facility ID:</th>
<th>P009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max. Design Rate:</td>
<td>38,000 tons of sheets per year per furnace (31 individual furnaces)</td>
</tr>
<tr>
<td>Capacity:</td>
<td>38,000 tons of sheets per year per furnace</td>
</tr>
<tr>
<td>Raw Materials:</td>
<td>Steel Coils, Annealing Gases, Coke Oven Gas, Natural Gas</td>
</tr>
<tr>
<td>Control Device:</td>
<td>N/A.</td>
</tr>
</tbody>
</table>

As identified above, Process P009 consists of 31 individual, moveable batch annealing furnaces with 58 stationary bases.

1. Restrictions:

   a. The HPH Annealing Furnaces shall only combust coke oven gas and natural gas. [§2102.04.b.5]

   b. The permittee shall not operate or allow to be operated, the HPH annealing furnaces in a manner such that emissions of PM-10 from the HPH annealing furnaces exceed at any time, 0.011 lbs/ton of steel. [§2104.02.d.1]

   c. The permittee shall not operate, or allow to be operated, HPH furnaces No. 1 through No. 31 in such manner that emissions of sulfur oxides from each furnace, expressed as sulfur dioxide, exceed 1.0 lb/MMBtu at any time: [§2104.03.a.2.A]

   d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in HPH furnaces No. 1 through No. 31, 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. [§2105.21.h.4]

   e. Emissions from HPH furnaces No. 1 through No. 31, shall not exceed the limitations in Table V-E-1 below at any time: [§2104.02.d.1, §2104.03.a.2.A and §2105.21.h.4]

**Table V-E-1 - HPH Annealing Furnace Emissions**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr † (each unit)</th>
<th>tons/yr † (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.04</td>
<td>0.10</td>
<td>0.43</td>
<td>13.33</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.04</td>
<td>0.10</td>
<td>0.43</td>
<td>13.33</td>
</tr>
<tr>
<td>NOx</td>
<td>0.49</td>
<td>0.74</td>
<td>3.22</td>
<td>99.82</td>
</tr>
<tr>
<td>CO</td>
<td>0.47</td>
<td>0.21</td>
<td>2.07</td>
<td>64.17</td>
</tr>
<tr>
<td>VOC</td>
<td>0.03</td>
<td>0.01</td>
<td>0.14</td>
<td>4.21</td>
</tr>
</tbody>
</table>

† A year is defined as any consecutive 12-month period
f. SO$_2$ emissions from the HPH Annealing Furnaces (aggregate) shall not exceed the limitations in Table V-A-2 below: [§2105.21.h; SO$_2$ SIP IP 0050-1008, Condition V.A.1.b]

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>12.0</td>
<td>13.58</td>
<td>52.56</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO$_2$ State Implementation Plan (SIP) Permit Revision and USEPA SO$_2$ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO$_2$ State Implementation Plan (SIP) Permit Revision and USEPA SO$_2$ Guidance dated September 14, 2017.

2. Testing Requirements:
   a. Emissions of SO$_2$ shall be determined by converting the H$_2$S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.E.1.f above. [SO$_2$ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]
   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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H$_2$S concentration (in grains/gr/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3; §§2103.12.i]
   b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.E.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.E.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (§2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain hourly, monthly, 12 month rolling totals of the fuel type, fuel usage (COG and natural gas), hours of operation and sulfur compound concentration expressed as H$_2$S in grains per 100 dscf in coke oven gas used for combustion, for the HPH Annealing Furnaces. [SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]
   b. The permittee shall calculate emissions to demonstrate compliance with conditions V.E.1.b, V.E.1.c and Table V-E-1. These calculations shall be recorded on a monthly basis.” [§2103.12.h.5.B]
   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 submit semiannual reports, as prescribed in General Condition III.15.d, of monthly fuel usage for each fuel combusted in the HPH Annealing Furnaces and the hours of operation of each furnace. [§2103.12.k]
   b. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]
   c. Reporting instances of non-compliance in accordance with V.E.5.b above does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Requirements:
   a. The permittee shall maintain and operate the HPH Annealing Furnaces in accordance with good combustion and air pollution control practices by performing regular maintenance, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258]

7. Additional Requirements:

   None except as provided elsewhere.

   PERMIT SHIELD IN EFFECT
F. Process P010: Open Coil Annealing Furnaces No. 1 Through No. 16

Process Description: The Open Coil Annealing Process consists of 16 individual furnaces that heat treat open coiled steel rolls. Each furnace is fired with coke oven gas that is enriched with natural gas. Furnaces No. 1 through No. 9 have a maximum heat input rating of 7.2 MMBTU/Hr each; furnaces No. 10 through No. 13 have a maximum heat input rating of 9.0 MMBTUs/Hr, each; furnace No. 14 has a maximum heat input rating of 5.4 MMBtu/hr and Furnaces No. 15 and 16 have a maximum heat input rating of 7.47 MMBtu/hr, each.

Facility ID: P010
Max. Design Rate: 176,000 tons of sheets per year
Capacity: 176,000 tons of sheets per year
Raw Materials: Steel Coils, Annealing Gases, Coke Oven Gas, Natural Gas
Control Device: N/A

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in the No. 1 through No. 16 Open Coil Annealing Furnaces. [§2102.04.b.5; §2102.04.b.6 and IP No. 0050-I006, Condition V.A.1.a ]

b. The permittee shall not operate or, or allow to be operated Open Coil Annealing Furnace No. 14 unless the furnace is properly operated and maintained according to the following specifications, at all times: [Installation Permit No. 0050-I003, and §2102.04.b.6]

   1) All furnace burners shall be low-NOX burners with maximum NOx emissions of 0.18 Lbs/MMBtu and 0.29 Lbs/MMBtu for natural gas and coke oven gas combustion, respectively.

   2) All burners shall combust natural gas and/or coke oven gas only.

   3) Natural gas fuel usage, adjusted to a heating value of 1,020 BTU/SCF shall not exceed 46.5 MMSCF per consecutive twelve-month period. Coke oven gas usage, adjusted to 514.4 BTU/SCF shall not exceed 92 MMSCF per consecutive twelve-month period.

   c. The permittee shall not operate, or allow to be operated Open Coil Annealing Furnace No. 14 unless the low-NOX burners specified in Condition V.F.1.b above are properly installed, maintained, and operated consistent with good air pollution control practice. [§2102.04.b.6]

   d. The permittee shall not operate or allow to be operated Open Coil Annealing Furnaces No. 1 through No. 13 fueled entirely by natural gas in such a manner that the emissions of particulate matter exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   e. The permittee shall not operate or allow to be operated Open Coil Annealing Furnaces No. 1 through No. 13 fueled entirely by coke oven gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   f. The permittee shall not operate or allow to be operated Open Coil Annealing Furnaces No. 1 through No. 13 fueled with natural gas and coke oven gas, in such a manner that the emissions of particulate matter exceeds the rate determined by the formula: [§2104.02.a.3]

   \[ A = \sum x_ia_i \]

   Where: \[ A = \text{Allowable emissions in pounds per million BTUs of actual heat input,} \]
   \[ i = \text{Fuel type (i.e. natural gas and coke oven gas),} \]
\[ x_i = \text{Fraction of total actual heat input in BTUs provided by fuel type } i, \text{ and} \]
\[ a_i = \text{Allowable emissions in pounds per million BTUs of actual heat input for fuel type } i, \text{ where } a_i = 0.008 \text{ for natural gas and 0.02 for coke oven gas.} \]

g. The permittee shall not operate, or allow to be operated, Open Coil Annealing Furnaces No. 1 through No. 13 in such manner that emissions of sulfur oxides, expressed as sulfur dioxide, exceed 1.0 lb/MMBtu at any time: [§2104.03.a.2.A]

h. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Open Coil Annealing Furnaces No. 1 through No. 16, 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. [§2105.21.h.4; IP-0050-I006, Condition V.A.1.b]

i. Emissions from Open Coil Annealing Furnaces No. 1 through No. 9, shall not exceed the limitations for each furnace in Table V-F-1 below at any time: [§2104.02.a.1, §2104.03.a.2.A and §2105.21.h.4]

<table>
<thead>
<tr>
<th>Table V-F-1 - Open Coil Annealing Furnace 1 through 9 Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pollutant</strong></td>
</tr>
<tr>
<td>----------------</td>
</tr>
<tr>
<td>Total Particulate</td>
</tr>
<tr>
<td>PM-10</td>
</tr>
<tr>
<td>NOx</td>
</tr>
<tr>
<td>CO</td>
</tr>
<tr>
<td>VOC</td>
</tr>
</tbody>
</table>

\(^1\) A year is defined as any consecutive 12-month period

j. Emissions from Open Coil Annealing Furnaces No. 10 through No. 13, shall not exceed the limitations for each furnace in Table V-F-2 below at any time: [§2104.02.a.1, §2104.03.a.2.A and §2105.21.h.4]

<table>
<thead>
<tr>
<th>Table V-F-2 - Open Coil Annealing Furnace 10 through 13 Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pollutant</strong></td>
</tr>
<tr>
<td>----------------</td>
</tr>
<tr>
<td>Total Particulate</td>
</tr>
<tr>
<td>PM-10</td>
</tr>
<tr>
<td>NOx</td>
</tr>
<tr>
<td>CO</td>
</tr>
<tr>
<td>VOC</td>
</tr>
</tbody>
</table>

\(^1\) A year is defined as any consecutive 12-month period

k. Emissions from Open Coil Annealing Furnace No. 14, shall not exceed the limitations in Table V-
F-3 below at any time:  [Installation Permit No. 0050-I003, §2104.02.a.1, §2104.03.a.2.A and §2105.21.h.4]

Table V-F-3 - Open Coil Annealing Furnace No. 14 Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.04</td>
<td>0.07</td>
<td>0.30</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.04</td>
<td>0.05</td>
<td>0.22</td>
</tr>
<tr>
<td>NOx</td>
<td>0.75</td>
<td>1.20</td>
<td>5.20</td>
</tr>
<tr>
<td>CO</td>
<td>0.47</td>
<td>0.21</td>
<td>2.10</td>
</tr>
<tr>
<td>VOC</td>
<td>0.03</td>
<td>0.02</td>
<td>0.13</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

l. The permittee shall not operate, or allow to be operated OCA furnaces No. 15 and No. 16 unless the furnace is properly installed, operated and maintained according to good combustion and air pollution control practices, at all times.  [§2102.04.b.6; IP No. 0050-I006, Condition V.A.1.c]

m. The permittee shall not operate, or allow to be operated OCA furnaces No. 15 and No. 16 unless the furnaces are equipped with low-NOX burners with maximum NOX emissions of 0.0375 lbs/MMBtu for natural gas combustion, corrected to 3 percent excess oxygen, and 0.0465 lbs/MMBtu for coke oven gas combustion, corrected to 3 percent excess oxygen.  [§2102.04.b.6 and IP No. 0050-I006, Condition V.A.1.d]

n. Emissions from Open Coil Annealing Furnaces No. 15 and No. 16, shall not exceed the limitations in Table V-F-1 below at any time:  [§§2105.21.h.4 and IP No. 0050-I006, Condition V.A.1.c]

Table V-F-4 - Open Coil Annealing Furnaces No. 15 and No. 16 Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each furnace (natural gas)</th>
<th>lbs/hr – each furnace (coke oven gas)</th>
<th>tons/yr¹ (each furnace)</th>
<th>tons/yr¹ (both furnaces)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.015</td>
<td>0.102</td>
<td>0.45</td>
<td>0.90</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.015</td>
<td>0.071</td>
<td>0.31</td>
<td>0.63</td>
</tr>
<tr>
<td>NOx</td>
<td>0.28</td>
<td>0.35</td>
<td>1.52</td>
<td>3.04</td>
</tr>
<tr>
<td>CO</td>
<td>0.68</td>
<td>0.30</td>
<td>2.96</td>
<td>5.93</td>
</tr>
<tr>
<td>VOC</td>
<td>0.044</td>
<td>0.020</td>
<td>0.19</td>
<td>0.39</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

o. SO₂ emissions from the Open Coil Annealing Furnaces No. 1 through No. 16 (aggregate) shall not exceed the limitations in Table V-F-5 below:  [§2105.21.h; SO₂ SIP IP 0050-1008, Condition
V.A.1.b]  

TABLE V-F-5  
SO\textsubscript{2} Emission Limitations for Open Coil Annealing Furnaces No. 1 through No. 16 (aggregate)

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>11.50</td>
<td>13.02</td>
<td>50.37</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO\textsubscript{2} State Implementation Plan (SIP) Permit Revision and USEPA SO\textsubscript{2} Guidance dated September 14, 2017.  
** Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO\textsubscript{2} State Implementation Plan (SIP) Permit Revision and USEPA SO\textsubscript{2} Guidance dated September 14, 2017.

2. Testing Requirements:

a. Emissions of SO\textsubscript{2} shall be determined by converting the H\textsubscript{2}S grain loading of the fuel burned and the fuel flow rate to pounds per hour to determine compliance with the emission limitations in condition V.F.1.o, Table V-A-5 above. [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]  
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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirement:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H\textsubscript{2}S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3.a; IP No. 0050-I006, Condition V.A.3; §§2103.12.j]  
b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.F.3.a V.E.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.F.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall record, hourly monthly, the type and total amount of fuel used (COG and natural gas) and the total production of furnaces No. 1 through No. 16, combined. [§2103.12.j and IP No. 0050-I003, 6/29/00 and IP No. 0050-I006, Condition V.A.4.a; SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.4.a]  
b. The permittee shall maintain monthly and 12 month rolling totals of the combined hours of operation of OCA Furnaces No. 1 through No. 16, and hourly summaries of the sulfur compound concentration expressed as H\textsubscript{2}S in grains per 100 dscf in coke oven gas used for combustion in
furnaces No. 1 through No. 16. [§2103.12.h.5.B, §2103.12.j and IP No. 0050-1006, Condition V.A.4.b; SO₂ SIP IP 0050-1008, Condition V.A.4.a]

c. 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. [§2102.04.b.5 and §2102.04.b.6 and IP No. 0050-1006, Condition V.A.4.c]

d. 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. [§2102.04.b.6 and IP No. 0050-1006, Condition V.A.4.d]

5. Reporting Requirements:

a. The permittee shall report the concentration of H₂S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO₂ SIP IP 0050-1008, Condition V.A.5.a; IP No. 0050-1006, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with condition V.F.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k and IP No. 0050-1006, Condition V.A.5.b]

6. Work Practice Requirements:

The permittee shall maintain and operate Open Coil Annealing Furnaces No. 1 through No. 16 in accordance with good combustion and air pollution control practices by performing regular maintenance, at all times, and measure the sulfur concentration of the coke oven gas with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258 and §2102.04.b.6]

7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
G. Process P011: Continuous Annealing

**Process Description:** The Continuous Annealing Process consists of one furnace rated at 45 MMBtu/hr along with associated coiling, uncoiling and cleaning equipment.

**Facility ID:** P011

**Max. Design Rate:** 348,000 tons of sheets per year

**Capacity:** 348,000 tons of sheets per year

**Raw Materials:** Steel Coils, Caustic Solutions, Annealing Gases, Coke Oven Gas, Natural Gas

**Control Device:** N/A

1. **Restrictions:**
   
a. Only coke oven gas and natural gas shall be combusted in the Continuous Annealing furnace. [§2102.04.b.5]

   b. The permittee shall not operate or allow to be operated Continuous Annealing furnace fueled entirely by natural gas in such a manner that the emissions of particulate matter exceed 0.008 lbs/MMBTU of actual heat input, at any time. [§2104.02.a.1]

   c. The permittee shall not operate or allow to be operated Continuous Annealing furnace fueled entirely by coke oven gas in such a manner that the emissions of particulate matter exceed 0.02 lbs/MMBTU of actual heat input, at any time. [§2104.02.a.1]

   d. The permittee shall not operate or allow to be operated Continuous Annealing furnace fueled with natural gas and coke oven gas, in such a manner that the emissions of particulate matter exceed the rate determined by the formula: [§2104.02.a.3]

   \[ A = \sum x_i a_i \]

   \( A = \) allowable emissions in pounds per million BTUs of actual heat input,

   \( i = \) fuel type (i.e. natural gas and coke oven gas),

   \( x_i = \) fraction of total actual heat input in BTUs provided by fuel type \( i \), and

   \( a_i = \) allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

   e. The permittee shall not operate, or allow to be operated, Continuous Annealing furnace in such manner that emissions of sulfur oxides, expressed as sulfur dioxide, exceed 1.0 lb/mmBtu at any time: [§2104.03.a.2.A]

   f. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Continuous Annealing furnace, 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. [§2105.21.h.4]
g. Emissions from Continuous Annealing Line furnace, shall not exceed the limitations specified Table V-G-1 below, at any time: [§2104.02.a.1, §2104.03.2.A, §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.36</td>
<td>0.90</td>
<td>3.94</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.36</td>
<td>0.90</td>
<td>3.94</td>
</tr>
<tr>
<td>NOx</td>
<td>4.50</td>
<td>18.00</td>
<td>78.84</td>
</tr>
<tr>
<td>CO</td>
<td>4.35</td>
<td>1.66</td>
<td>19.04</td>
</tr>
<tr>
<td>VOC</td>
<td>0.28</td>
<td>0.12</td>
<td>1.25</td>
</tr>
</tbody>
</table>

¹A year is defined as any consecutive 12-month period

h. SO₂ emissions from the Continuous Annealing Furnace shall not exceed the limitations in Table V-G-2 below: [§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b; §2104.03.2.A, §2105.21.h.4]

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)</th>
<th>Supplementary 24-hr Limit (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.07</td>
<td>9.14</td>
<td>35.35</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 2.

2. Testing Requirements:
   a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.G.1.h above. [§2103.12.h]
   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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. The permittee shall measure monthly the quantity of natural gas and coke oven gas combusted in the Annealing Furnace. [§2103.12.i]
   b. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]
c. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.G.3.b V.E.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.G.3.b. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-1006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order Number 258]
      1) The date of the annual tune-up;
      2) The name of the service company and/or individuals performing the annual tune-up;
      3) The operating rate or load after the annual tune-up; and
      4) The CO and NOx emission rate after the annual tune-up.
   b. The permittee shall maintain hourly records of fuel type, fuel usage (COG and natural gas), hours of operation, and hourly H2S concentration in grains per 100 dscf. [SO2 SIP IP 0050-1008, Condition V.A.4.a; §§2103.12.h.5.B; §§2103.12.j; §2103.12.h.5.B]
   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 concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]
   b. Reporting instances of non-compliance in accordance with V.G.5.a does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Requirements:
   a. The permittee shall perform an annual adjustment or "tune-up" on the combustion process of the equipment once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No. 258]
      1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
      2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of carbon monoxide (hereafter referred as "CO"); and
      3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.
PERMIT SHIELD IN EFFECT
H. Process P012: No. 1 Continuous Galvanizing Line

Process Description: The Continuous Galvanizing Process consists of one natural gas-fired preheat furnace rated at 50 MMBTUs/hr, along with associated coiling, uncoiling and cleaning equipment.

Facility ID: P012
Max. Design Rate: 187,700 tons of sheets per year
Capacity: 187,700 tons of sheets per year
Raw Materials: Steel Coils, Zinc, Treatment Chemicals, and Natural Gas
Control Device: N/A

1. Restrictions

a. Only natural gas shall be combusted in the No. 1 Continuous Galvanizing Line preheat furnace [§2102.04.b.5]

b. The permittee shall not operate, or allow to be operated the No. 1 Galvanizing Line Preheat Furnace in such a manner that the emissions of particulate matter from each furnace exceeds 0.008 lbs/MMBTUs when combusting natural gas. [§2104.02.a.1]

c. Emissions from the continuous galvanizing line (preheat furnace) shall not exceed the limitations specified in Table V-H-1 below, at any time: [§2104.02.a.1.A and §2104.03.a.1]

Table V-H-1 - No. 1 Continuous Galvanizing Line Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Preheat Furnace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lbs/hr (natural gas)</td>
</tr>
<tr>
<td>Particulate Matter</td>
<td>0.40</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.40</td>
</tr>
<tr>
<td>CO</td>
<td>4.83</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.03</td>
</tr>
<tr>
<td>NOₓ</td>
<td>3.0</td>
</tr>
<tr>
<td>VOC</td>
<td>0.32</td>
</tr>
</tbody>
</table>

1A year is defined as any consecutive 12-month period

2. Testing Requirements:

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

3. Monitoring Requirements:

The permittee shall monitor the monthly quantity of natural gas combusted in the No. 1 Galvanizing Line furnaces. [§2103.12.i]
4. **Record Keeping Requirements:**
   
a. The permittee shall maintain monthly, 12 month rolling totals of the following data for the No. 1 Galvanizing Line Preheat Furnace [§2103.12.5.B]
   
   1) Fuel usage;
   2) Monthly production (tons of sheet processed);
   3) Hours of operation.

   b. 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 to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. If all the terms and conditions of this permit are complied with during the reporting period, then no report is necessary under this permit condition. [§2103.12.k]

   b. Reporting instances of non-compliance in accordance with V.H.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. **Work Practice Standards:**
   
a. The permittee shall maintain and operate the No. 1 Continuous Galvanizing Line in accordance with good combustion and air pollution control practices by performing regular maintenance, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258]

7. **Additional Requirements:**
   
None except as provided elsewhere.

---

**PERMIT SHIELD IN EFFECT**
I. Process P013: No. 2 Continuous Galvanizing & Aluminum Coating Lines

**Process Description:** The Continuous Galvanizing & Aluminum Coating Process consists of one preheat furnace rated at 18 MMBTUs/Hr along with associated cleaning, treating and galvalume equipment

**Facility ID:** P013

**Max. Design Rate:** 156,400 tons of sheets per year

**Capacity:** 156,400 tons of sheets per year

**Raw Materials:** Steel Coils, Natural Gas, Zinc, Galvalume, Treatment Chemicals, Caustic Solution, Annealing Gases, Coating Oil

**Control Device:** NA

1. **Restrictions:**

   a. Only natural gas shall be combusted in the No. 2 Continuous Galvanizing and Aluminum Coating Line preheat furnace. [§2102.04.b.5]

   b. The permittee shall not operate, or allow to be operated the No. 2 Galvanizing & Aluminum Coating Line Preheat Furnace in such a manner that the emissions of particulate matter exceed 0.008 lbs/MMBTU when combusting natural gas. [§2104.02.a.1]

   c. The permittee of each coil coating line shall limit organic HAP emissions to no more than 0.046 kilograms (kg) of organic HAP per liter of solids applied during each 12-month compliance period. [§63.5120(a)(2)]

   d. Emissions from the preheat furnace shall not exceed the limitations specified in Table V-I-1 below, at any time: [§2104.02.a.1.A and §2104.03.a.1]

**Table V-I-1 - No. 2 Continuous Galvanizing & Aluminum Coating Lines Emission Limits**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>Tons/Yr¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.14</td>
<td>0.61</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.14</td>
<td>0.61</td>
</tr>
<tr>
<td>CO</td>
<td>1.74</td>
<td>7.62</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.01</td>
<td>0.04</td>
</tr>
<tr>
<td>NOₓ</td>
<td>7.20</td>
<td>31.54</td>
</tr>
<tr>
<td>VOC</td>
<td>0.11</td>
<td>0.48</td>
</tr>
</tbody>
</table>

¹A year is defined as any consecutive 12-month period

2. **Testing Requirements:**

   a. On and after June 10, 2005, the permittee shall determine the organic HAP weight fraction of each coating material applied by following one of the procedures in paragraphs §63.5160(b)(1) through (4) and the solids content of each coating material applied by following the procedure in paragraph §63.5160(c). [§63.5160]
b. For the purpose of demonstrating continuous compliance with Condition V.I.1.c above, a compliance period consists of 12 months. Each month after the end of the initial compliance period is the end of a compliance period consisting of that month and the preceding 11 months. [§63.5130(e)]

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

3. Monitoring Requirements:

a. The permittee shall demonstrate compliance with the emission limitation in Condition V.I.1.c above by using at least one of the compliance options in §63.5170(a) or (b). The permittee may apply any of the compliance options to an individual coil coating line, or to multiple lines as a group, or to the entire affected source. [§63.5170(a) and (b)]

4. Record Keeping Requirements:

a. The permittee shall maintain monthly, 12 month rolling totals of the following data for the No. 2 Galvanizing & Aluminum Coating Line Preheat Furnace: [§2103.12.h.5.B]

   1) Fuel usage;
   2) Hours of operation;
   3) Production (tons of sheet processed).

b. On and after June 10, 2005, the permittee subject to 40 CFR 63, Subpart SSSS shall maintain the following records: [§63.5190(a)]

   1) Records of the coating lines on which the permittee used each compliance option in Condition V.I.3.a above and the time periods (beginning and ending dates and times) the permittee used each option.

   2) Records specified in 40 CFR Part 63, §63.10(b)(2) of all measurements needed to demonstrate compliance including:

      i. Organic HAP content data for the purpose of demonstrating compliance in accordance with §63.5160(b);
      ii. Volatile matter and solids content data for the purpose of demonstrating compliance in accordance with §63.5160(c);
      iii. Material usage, HAP usage, volatile matter usage, and solids usage and compliance demonstrations using these data in accordance with §63.5170(a) and (b);

   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 to the Department every six months, in accordance with General Condition III.15.d, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. If all the terms and conditions of this permit are complied with during the reporting period, then no report is necessary under this permit condition. [§2103.12.k]
b. The permittee shall maintain records that document that initial notification was made in accordance with 40 CFR Part 63, Subpart SSS [§63.5180(b)]

c. The permittee shall submit semi-annual compliance reports containing the following information: [§63.5180(g)]

1) The semi-annual compliance report shall contain the following information:
   i. Company name and address.
   ii. Statement by a responsible official with that official's name, title, and signature, certifying the accuracy of the content of the report.
   iii. Date of report and beginning and ending dates of the reporting period. The reporting period is the 6-month period ending on June 30 or December 31. Note that the information reported for each of the 6 months in the reporting period will be based on the last 12 months of data prior to the date of each monthly calculation.
   iv. Identification of the compliance option or options specified in Table 1 to 40 CFR Part 63, §63.5170 that the permittee used on each coating operation during the reporting period. If you switched between compliance options during the reporting period, you must report the beginning dates you used each option.
   v. A statement that there were no deviations from the standards during the reporting period.

d. The permittee shall submit, for each deviation occurring at an affected source subject to Subpart SSSS, the semi-annual compliance report containing the information in Condition V.I.5.c.1) above and the following information: [§63.5180(h)]

1) The total operating time of each affected source during the reporting period.
2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable, and the corrective action taken.
3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause other than downtime associated with zero and span and other daily calibration checks, if applicable).

e. Reporting instances of non-compliance in accordance with V.I.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:
   a. The permittee shall maintain and operate the No. 2 Continuous Galvanizing and Aluminum Coating Line in accordance with good combustion and air pollution control practices by performing regular maintenance, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258]

7. Additional Requirements:

None except as provided elsewhere

PERMIT SHIELD IN EFFECT
J. Process P015: Coke Oven Gas Flares No. 1 through No. 3 and Peachtree A & B Flare

**Process Description:** Four flares used for combusting excess coke oven gas.

**Facility ID:** P015

**Max. Design Rate:** 6.75 million cubic feet per day of COG, each

**Capacity:** 27 million cubic feet per day for four flares

**Raw Materials:** Coke oven gas

**Control Device:** N/A

1. **Restrictions:**
   a. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in C.O.G Flares No.1 to No. 3 and Peachtree Flare, 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. [§2105.21.h.4, 25 PA Code §129.99]

2. **Testing Requirements:**
   a. The Department reserves the right to require emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with §2108.02. (§2103.12.h.1)

3. **Monitoring Requirements:**
   a. The permittee shall measure the sulfur concentration of all coke oven gas used for combustion or flaring at the facility, a minimum of once per each successive twenty-four hour time period. The sulfur concentration shall be expressed and recorded as hydrogen sulfide. Measurements of hydrogen sulfide concentrations in coke oven gas shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy this condition (V.K.3.a). However, if there is a change to the current operating scenario, the sulfur concentration measurements required by this condition (V.K.3.a) will be taken at the Irvin Plant. [§2103.12.h.5.B]

4. **Record Keeping Requirements**
   a. The permittee shall maintain daily and 12 month rolling totals of the fuel usage, COG sulfur concentration (expressed as H₂S) and hours of operation for Flares No.1, No. 2 and No. 3 and the Peachtree Flare: [§2103.12.h.5.B, 25 PA Code §129.100]

   b. 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; 25 PA Code §129.100]

5. **Reporting Requirements:**
   a. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]

   b. Reporting instances of non-compliance in accordance with V.J.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]
6. Work Practice Standards:

None except as provided elsewhere.

7. Additional requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
K. Boiler No. 1

**Process Description:** One 79.8 MMBTUs/hr natural gas and coke oven gas fired boiler

**Facility ID:** B001

**Max. Design Rate:** 79.8 MMBtu/hr

**Capacity:** 79.8 MMBtu/hr

**Raw Materials:** Coke oven gas and natural gas

**Control Device:** N/A

This emission unit is also subject to the following requirements and restrictions:

1. **Restrictions:**

   a. Only coke oven gas and natural gas shall be combusted in Boiler No. 1. [2102.04.b.5]

   b. The permittee shall not operate, or allow to be operated Boiler No. 1 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter exceed 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   c. The permittee shall not operate, or allow to be operated Boiler No. 1 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   d. The permittee shall not operate or allow to be operated Boiler No. 1 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No. 1 exceeds the rate determined by the formula: [§2104.02.a.3]

      \[
      A = \sum x_i a_i
      \]

      Where: \( A = \) allowable emissions in pounds per million BTUs of actual heat input,

      \( i = \) fuel type (i.e. natural gas and coke oven gas),

      \( x_i = \) fraction of total actual heat input in BTUs provided by fuel type \( i \), and

      \( a_i = \) allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

   e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 1, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 1, shall not exceed the limitations specified in Table V-K-1 below, at any time:  [§2104.03, §2104.02.b, §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.64</td>
<td>1.60</td>
<td>6.99</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.64</td>
<td>1.60</td>
<td>6.99</td>
</tr>
<tr>
<td>NOx</td>
<td>7.98</td>
<td>12.77</td>
<td>55.92</td>
</tr>
<tr>
<td>CO</td>
<td>7.71</td>
<td>3.38</td>
<td>33.76</td>
</tr>
<tr>
<td>VOC</td>
<td>0.51</td>
<td>0.22</td>
<td>2.21</td>
</tr>
</tbody>
</table>

1 A year is defined as any consecutive 12-month period

g. SO\textsubscript{2} emissions from Boiler No. 1 shall not exceed the limitations in Table V-K-2 below:  [§§2105.21.h; SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.1.b]

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.88</td>
<td>8.92</td>
<td>34.51</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO\textsubscript{2} State Implementation Plan (SIP) Permit Revision and USEPA SO\textsubscript{2} Guidance dated September 14, 2017.  
**Tons/year value is used to demonstrate the expected tons/year from this unit.  The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value.  These limits are based on ACHD’s SO\textsubscript{2} State Implementation Plan (SIP) Permit Revision and USEPA SO\textsubscript{2} Guidance dated September 14, 2017.

2. Testing Requirements:

a. Emissions of SO\textsubscript{2} shall be determined by converting the H\textsubscript{2}S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.K.1.g, Table V-K-2 above.  [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.2.b §2103.12.h]

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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H\textsubscript{2}S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b.  Continuously shall be defined as at least once every 15 minutes.  [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.K.3.a above shall be conducted according to Section §2107.08 of Article XXI.  Under the current
operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.K.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-1006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258, §2105.06, and §2103.12.j; 40 CFR 63, Subpart DDDDD; 25 PA Code §129.100]

1) The date of the annual tune-up;
2) The name of the service company and/or individuals performing the annual tune-up;
3) The operating rate or load after the annual tune-up;
4) The CO and NOX emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly, 12-month rolling totals of the following data for Boiler no. 1: [SO2 SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

1) Fuel type, fuel usage, hours of operation and sulfur concentration expressed as H2S in grain per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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; 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with GeneralIII.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.K.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 1 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No. 258; 25 PA Code §129.99]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and
3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. Additional Requirements:

None except as provided elsewhere

PERMIT SHIELD IN EFFECT
L. Boiler No. 2

Process Description: One 84.6 MMBTUs/Hr natural gas and coke oven gas fired boiler
Facility ID: B002
Max. Design Rate: 84.6 MMBtu/hr
Capacity: 84.6 MMBtu/hr
Raw Materials: Coke oven gas and natural gas
Control Device: NA

1. Restrictions:

   a. Only coke oven gas and natural gas shall be combusted in Boiler No. 2. [2102.04.b.5]

   b. The permittee shall not operate, or allow to be operated Boiler No. 2 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 1 exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   c. The permittee shall not operate, or allow to be operated Boiler No. 2 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   d. The permittee shall not operate or allow to be operated Boiler No. 2 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No.2 exceeds the rate determined by the formula: [§2104.02.a.3]

   \[
   A = \sum x_i a_i \quad \text{where} \quad A = \text{allowable emissions in pounds per million BTUs of actual heat input},
   \]

   \[
   i = \text{fuel type (i.e. natural gas and coke oven gas)},
   \]

   \[
   x_i = \text{fraction of total actual heat input in BTUs provided by fuel type } i, \text{ and}
   \]

   \[
   a_i = \text{allowable emissions in pounds per million BTUs of actual heat input for fuel type } i, \text{ where } a_i = 0.008 \text{ for natural gas and 0.02 for coke oven gas.}
   \]

   e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 2, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 2, shall not exceed the limitations in Table V-L-1 below, at any time: [

§2104.03, §2104.02.b, §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.68</td>
<td>1.69</td>
<td>7.41</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.68</td>
<td>1.69</td>
<td>7.41</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.05</td>
<td>18.20</td>
<td>45.90</td>
</tr>
<tr>
<td>NOx</td>
<td>8.46</td>
<td>13.54</td>
<td>59.29</td>
</tr>
<tr>
<td>CO</td>
<td>8.17</td>
<td>3.58</td>
<td>35.80</td>
</tr>
<tr>
<td>VOC</td>
<td>0.54</td>
<td>0.23</td>
<td>2.37</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

g. SO₂ emissions from Boiler No. 1 shall not exceed the limitations in Table V-L-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>8.36</td>
<td>9.46</td>
<td>36.62</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:

a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.L.1.g, Table V-L-2 above. [SO₂ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]

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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.L.3.a
above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.L.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart DDDDD; 25 PA Code §129.100]

      1) The date of the annual tune-up;
      2) The name of the service company and/or individuals performing the annual tune-up;
      3) The operating rate or load after the annual tune-up;
      4) The CO and NOx emission rate before and after the annual tune-up; and
      5) The excess oxygen rate after the annual tune-up.
   b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler No. 2: [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.3; §2103.12.h.5.B]

      1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H\textsubscript{2}S in grains per 100 dscf in coke oven gas used for combustion, for the subject boiler.
   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; 25 PA Code §129.100]

5. Reporting Requirements:
   a. The permittee shall report the concentration of H\textsubscript{2}S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]
   b. Reporting instances of non-compliance in accordance with V.L.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:
   a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 2 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258; 25 PA Code §129.99]

      1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
      2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NO\textsubscript{x}, and to the extent practicable minimize emissions of carbon monoxide
(hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
M. Boiler No. 3

Process Description: One 41.6 MMBTUs/Hr natural gas and coke oven gas fired boiler
Facility ID: B003
Max. Design Rate: 41.6 MMBtu/hr
Capacity: 41.6 MMBtu/hr
Raw Materials: Coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in Boiler No. 3. [2102.04.b.5]

b. The permittee shall not operate, or allow to be operated Boiler No. 3 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 1 exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

c. The permittee shall not operate, or allow to be operated Boiler No. 3 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

d. The permittee shall not operate or allow to be operated Boiler No. 3 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No.3 exceeds the rate determined by the formula: [§2104.02.a.3]

\[ A = \sum x_i a_i \]

Where \( A \) = allowable emissions in pounds per million BTUs of actual heat input,

\( i \) = fuel type (i.e. natural gas and coke oven gas),

\( x_i \) = fraction of total actual heat input in BTUs provided by fuel type \( i \), and

\( a_i \) = allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 3, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 3, shall not exceed the limitations specified in Table V-M-1 below, at any time:  [§2104.03, §2104.02.b, §2105.21.h.4]  

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>NOx</td>
<td>4.16</td>
<td>6.66</td>
<td>29.15</td>
</tr>
<tr>
<td>CO</td>
<td>4.02</td>
<td>1.76</td>
<td>17.60</td>
</tr>
<tr>
<td>VOC</td>
<td>0.26</td>
<td>0.11</td>
<td>1.15</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period  

g. SO₂ emission from Boiler No. 3 (aggregate) shall not exceed the limitations in condition IV.26.c above:  [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]  

2. Testing Requirements:  
a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition IV.26.c, Table IV-1 above. [SO₂ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]  
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 §2108.02. (§2103.12.h.1)  

3. Monitoring Requirements:  
a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]  
b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.M.3.a V.E.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.M.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)  

4. Record Keeping Requirements:  
a. The permittee shall maintain the following records of the annual tune-up for the subject equipment:  
[RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart DDDD]  
1) The date of the annual tune-up;  
2) The name of the service company and/or individuals performing the annual tune-up;  
3) The operating rate or load after the annual tune-up;
4) The CO and NOx emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler No. 3: [SO2 SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H2S in grains per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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 concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.M.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 3 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. Additional Requirements:

None except as provided elsewhere.
N. Boiler No. 4

Process Description: One 41.6 MMBTUs/Hr natural gas and coke oven gas fired boiler
Facility ID: B004
Max. Design Rate: 41.6 MMBtu/hr
Capacity: 41.6 MMBtu/hr
Raw Materials: Coke oven gas and natural gas
Control Device: NA

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in Boiler No. 4. [2102.04.b.5]

b. The permittee shall not operate, or allow to be operated Boiler No. 4 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 4 exceeds 0.008 lbs./MMBTU of actual heat input, at any time or Boiler No. 4 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

c. The permittee shall not operate or allow to be operated Boiler No. 4 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No. 4 exceeds the rate determined by the formula: [§2104.02.a.3]

\[ A = \sum x_i a_i \]

Where: A = allowable emissions in pounds per million BTUs of actual heat input,

\[ x_i \] = fraction of total actual heat input in BTUs provided by fuel type i, and

\[ a_i \] = allowable emissions in pounds per million BTUs of actual heat input for fuel type i, where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 4, 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. [§2105.21h.4]
e. Emissions from Boiler No. 4, shall not exceed the limitations specified in Table V-N-1 below, at any time: [§2104.03, §2104.02.b, §2105.21.h.4]

<table>
<thead>
<tr>
<th>POLLUTANT</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.33</td>
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<td>3.64</td>
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</tr>
<tr>
<td>VOC</td>
<td>0.26</td>
<td>0.11</td>
<td>1.15</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period.

f. SO\textsubscript{2} emission from Boiler No. 4 (aggregate) shall not exceed the limitations in condition IV.26.c above: [§§2105.21.h; SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.1.b]

2. Testing Requirements:
   a. Emissions of SO\textsubscript{2} shall be determined by converting the H\textsubscript{2}S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition IV.26.c, Table IV-1 above. [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]
   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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H\textsubscript{2}S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]
   b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.N.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.N.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-1006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart DDDDD]
      1) The date of the annual tune-up;
      2) The name of the service company and/or individuals performing the annual tune-up;
      3) The operating rate or load after the annual tune-up;
4) The CO and NO\textsubscript{x} emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler no. 4: [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H\textsubscript{2}S in grain per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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 concentration of H\textsubscript{2}S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.N.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 4 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NO\textsubscript{x}, and to the extent practicable minimize emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
O. Fugitive Particulate Emissions From Roads and Vehicles

Process Description: Approximately 3.23 miles of paved roads, approximately 0.85 miles of unpaved roads, and approximately 4.3 acres of parking areas.

Facility ID: F001

1. Restrictions:
   a. The permittee shall apply a chemical dust suppressant to the entire surface of all unpaved parking areas in use on the west side of the plant and on all unpaved roads at appropriate rates and intervals of time to maximize dust suppression and comply with Site Level Conditions IV.18, IV.19 and IV.23 above. [§2105.40, §2105.42 and §2105.49]
   b. The permittee shall comply with the following conditions for the paved road from the railroad trestle to the loading dock at the Irvin Plant and any paved road and paved areas at the coal storage area at the Irvin Plant to comply with Site Level Conditions IV.18, IV.19 and IV.23 above. [§2105.40, §2105.42 and §2105.49]
      1) Properly maintain, repair, patch and repave all paved roads and areas.

2. Testing Requirements:

   None except as provided elsewhere.

3. Monitoring Requirements:

   None except as provided elsewhere.

4. Record Keeping Requirements:

   a. The permittee shall record or have access to records that list the date, time, amount of undiluted chemical dust suppressant and the dilution ratio of each application of chemical dust suppressant. [§2103.12.j]

5. Reporting Requirements:

   a. The permittee shall prepare a report within 30 days of each calendar quarter, in accordance with General Condition III.15.e, that includes: [§2103.12.k]
      1) An identification of any maintenance, repairs, patching or repaving of the paved roads or areas.
      2) The dates on which chemical dust suppressant was applied, and for each date, the location(s) and the dilution ratio(s) of the application.
   b. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]
   c. Reporting instances of non-compliance in accordance with Conditions V.O.5.a and V.O.5.b above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standard:
None except as provided elsewhere.

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
P. Solvents Parts Cleaning

Process Description: Solvents parts cleaning for maintenance.

Facility ID: F002

1. Restrictions:

   a. The permittee shall maintain all cleaning solvents containing volatile organic compounds in closed containers at all times except when in use. [§2103.12.a.2.B]

   b. The permittee shall clean any spilled cleaning solvent that contains volatile organic compounds as expeditiously as possible. [§2103.12.a.2.B]

   c. The emissions from parts solvent cleaning shall not exceed 30 tons/year of volatile organic compounds or 1.0 tons of hazardous air pollutants.

   d. The permittee shall not operate, or allow to be operated, any cold cleaning degreaser with a degreaser opening exceeding ten (10) square feet, unless [§2105.15.a, 25 PA Code §129.99]:

      1) There is in operation on such degreaser:

         i. A cover to prevent evaporation of solvent during periods of non-use;
         ii. Equipment for draining cleaned parts; and
         iii. A permanent conspicuous label summarizing the operating requirements set forth in Paragraph V.P.1.d.2) below; and

      2) Such degreaser is operated at all times in such manner that:

         i. Waste solvents are transferred to another party or disposed of by means insuring that no more than 20% by weight of the solvents evaporate into the open air;
         ii. Waste solvents are stored in covered containers;
         iii. The degreaser cover is closed when parts are not being processed through the degreaser; and,
         iv. Cleaned parts are drained for at least 15 seconds or until dripping ceases.

   e. Compliance with the above VOC and HAP emission limitations shall be determined by accepted mass balance methodology applied to records of solvent usage and recovery. A year shall be defined as any 12 consecutive months for the above emission limitations. [§2103.12.5.B25 PA Code §129.100]

2. Testing Requirements:

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

3. Monitoring Requirements:

   None except as provided elsewhere.

4. Record Keeping Requirements:

   a. The permittee shall maintain records of the type of cleaning solvent used, the pounds of VOC per gallon of the solvent, the amount purchased and the amount disposed of for each cleaning solvent
containing volatile organic compounds sufficient to demonstrate compliance with the above emission limitations by Condition V.P.1.e above. These records shall be compiled on a 12 month rolling total basis. [§2103.12.h.5.B, 25 PA Code §129.100]

b. 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, 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]

b. Reporting instances of non-compliance in accordance with Condition V.P.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

None except as provided elsewhere.

7. Additional Requirements:

None except as provided elsewhere

PERMIT SHIELD IN EFFECT
VI. ALTERNATIVE OPERATING SCENARIOS

No alternative operating scenarios exist for this facility

PERMIT SHIELD IN EFFECT
VII. MISCELLANEOUS

PERMIT SHIELD IN EFFECT
VIII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the estimated annual maximum potential emissions, including the four flares from the U. S. Steel Mon Valley Works - Irvin Plant. These annual (consecutive 12 month) emission estimates assume that all sources operate continuously at their maximum capacity.

<table>
<thead>
<tr>
<th>POLLUTANT</th>
<th>tons/year ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate</td>
<td>123.89</td>
</tr>
<tr>
<td>PM-10</td>
<td>124.52</td>
</tr>
<tr>
<td>SO₂</td>
<td>1,248.74</td>
</tr>
<tr>
<td>NOₓ</td>
<td>749.15</td>
</tr>
<tr>
<td>CO</td>
<td>1,179.08</td>
</tr>
<tr>
<td>VOC</td>
<td>203.99</td>
</tr>
<tr>
<td>Lead</td>
<td>0.08</td>
</tr>
<tr>
<td>Hydrochloric Acid</td>
<td>36.77</td>
</tr>
</tbody>
</table>

¹A year is defined as any consecutive 12-month period.
I. Executive Summary

The U.S. Steel Irvin Works (Irvin) is defined as a major source of NOx 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 no changes since emission sources were either exempt, additional changes were not technically or financially feasible, or changes had previously been made and were already incorporated into issued permits.

Table 1  Technically and Financially Feasible Control Options Summary for NOx

<table>
<thead>
<tr>
<th>Control Options Summary for NOx</th>
</tr>
</thead>
<tbody>
<tr>
<td>There are no technically feasible control options that are reasonably achievable for any processes at this facility.</td>
</tr>
</tbody>
</table>

These findings are based on the following documents:

- RACT analysis performed by ERG (U S Steel Irvin – RACTEval_2-20_15.doc)
- RACT analysis performed by U.S. Steel (0050c2014-04-04ract.pdf)

II. Regulatory Basis

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 determination of RACT for U.S. Irvin Works submitted by the subject source and supplemented with additional information as needed by ACHD.
III. Facility Description, Sources of NOx, and Sources of VOCs

The U. S. Steel Irvin Works is a secondary steel processing facility located in West Mifflin Borough, Allegheny County, Pennsylvania. The Irvin Plant receives steel slabs and performs one of several finishing processes on the steel slabs. The finishing processes commonly referred to as secondary steel processes, include hot and cold rolling, continuous pickling, annealing, and galvanizing. The facility is composed of an 80” hot strip mill, 64” & 84” continuous hydrochloric acid pickle lines, a cold reduction mill, HPH annealing furnaces, open coil annealing furnaces, a continuous annealing furnace, continuous galvanizing line no. 1, continuous galvanizing and aluminum coating line no. 2, a continuous terne line, four coke oven gas flares, and four natural gas/coke oven gas fired boilers.

The facility is a major source of NOx and VOCs.

### Table 2 Facility Sources Subject to Case-by-Case RACT II and Existing RACT I Limits

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Combustion Fuel</th>
<th>Rating</th>
<th>NOx PTE (TPY)</th>
<th>NOx Presumptive Limit (RACT II)</th>
<th>VOC PTE (TPY)</th>
<th>VOC Presumptive Limit (RACT II)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P001</td>
<td>80-inch hot strip mill, five reheat furnaces</td>
<td>Coke Oven Gas</td>
<td>140 MMBtu/hr each furnace</td>
<td>220.1 ton/yr each furnace</td>
<td>None</td>
<td>6.2 ton/yr each furnace</td>
<td>None</td>
</tr>
<tr>
<td>P008</td>
<td>Cold Reduction Mill</td>
<td>None</td>
<td>2.5 million ton/yr steel coil</td>
<td>None</td>
<td>None</td>
<td>13.1 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>P015</td>
<td>Coke Oven Gas Flares</td>
<td>Coke Oven Gas</td>
<td>6.75 million ft³/day COG</td>
<td>180 ton/yr</td>
<td>None</td>
<td>168 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler 1</td>
<td>Coke Oven Gas</td>
<td>79.8 MMBtu/hr</td>
<td>55.9 ton/yr</td>
<td>None</td>
<td>2.2 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>B002</td>
<td>Boiler 2</td>
<td>Coke Oven Gas</td>
<td>84.6 MMBtu/hr</td>
<td>59.3 ton/yr</td>
<td>None</td>
<td>2.4 ton/yr</td>
<td>None</td>
</tr>
<tr>
<td>F002</td>
<td>Solvents Parts Cleaning</td>
<td>None</td>
<td>-</td>
<td>None</td>
<td>None</td>
<td>10.6 ton/yr</td>
<td>None</td>
</tr>
</tbody>
</table>

### Table 3 Facility Sources Subject to the Presumptive RACT II per PA Code 129.97

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Combustion Fuel</th>
<th>Rating</th>
<th>NOx PTE (TPY)</th>
<th>VOC PTE (TPY)</th>
<th>Presumptive RACT Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>P009</td>
<td>Thirty-One annealing furnaces</td>
<td>Coke Oven Gas</td>
<td>Each furnace is rated at 4.9 MMBtu/hr (&lt;20 MMBtu/hr)</td>
<td>99.82</td>
<td>4.21</td>
<td>Install, maintain, and operate the source in accordance with the manufacturer’s specifications and with good operating practices [§129.97(c)(3)] since each furnace’s heat input is less than 20 MMBtu/hr</td>
</tr>
<tr>
<td>P010</td>
<td>Sixteen annealing furnaces</td>
<td>Coke Oven Gas</td>
<td>All furnaces are rated less than 20 MMBtu/hr</td>
<td>184</td>
<td>3.4</td>
<td>Install, maintain, and operate the source in accordance with the manufacturer’s specifications and with good operating practices [§129.97(c)(3)] since each furnace’s heat input is less than 20 MMBtu/hr</td>
</tr>
<tr>
<td>P011</td>
<td>continuous annealing</td>
<td>Coke Oven Gas</td>
<td>45 MMBtu/hr</td>
<td>78.8</td>
<td>1.3</td>
<td>Presumptive RACT is a biennial tune-up (already implemented) since the furnace’s heat input is &lt; 50 MMBtu/hr §129.97(b)(1)</td>
</tr>
<tr>
<td>P012</td>
<td>no. 1 continuous galvanizing line</td>
<td>Natural Gas</td>
<td>50 MMBtu/hr</td>
<td>13.1</td>
<td>1.4</td>
<td>Presumptive RACT is 0.10 lb NOx/MMBtu §129.97(g)(1)</td>
</tr>
<tr>
<td>P013</td>
<td>no. 2 continuous galvanizing lines</td>
<td>Natural Gas</td>
<td>The furnace is rated at 18 MMBtu/hr (&lt;20 MMBtu/hr)</td>
<td>31.5</td>
<td>0.5</td>
<td>Install, maintain, and operate the source in accordance with the manufacturer’s specifications and with good operating practices [§129.97(c)(3)] since each furnace’s heat input is less than 20 MMBtu/hr</td>
</tr>
<tr>
<td>B003</td>
<td>Boiler 3</td>
<td>Coke Oven Gas</td>
<td>41.6 MMBtu/hr</td>
<td>29.2</td>
<td>1.2</td>
<td>Presumptive RACT is a biennial tune-up (already implemented) since the furnace’s heat input is &lt; 50 MMBtu/hr §129.97(b)(1)</td>
</tr>
<tr>
<td>B004</td>
<td>Boiler 4</td>
<td>Coke Oven Gas</td>
<td>41.6 MMBtu/hr</td>
<td>29.2</td>
<td>1.2</td>
<td>Presumptive RACT is a biennial tune-up (already implemented) since the furnace’s heat input is &lt; 50 MMBtu/hr §129.97(b)(1)</td>
</tr>
</tbody>
</table>
Table 4  
Facility Sources Exempt from RACT II per PA Code 129.96(c) \(< 1\) TPY NO\(_X\); \(< 1\) TPY VOC

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Combustion Fuel</th>
<th>Rating</th>
<th>NO(_X) PTE (TPY)</th>
<th>VOC PTE (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P002</td>
<td>64&quot; continuous coil HCL pickle</td>
<td>None</td>
<td>1.05 million tons of steel sheets/yr</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>P007</td>
<td>84&quot; continuous pickle line</td>
<td>None</td>
<td>1.58 million tons of steel sheets/yr</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>F001</td>
<td>Fugitive particulates from roads</td>
<td>None</td>
<td>3.2 miles of paved roads</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.9 miles of unpaved roads</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>4.3 acres of parking lots</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

IV. RACT Determination

A detailed RACT Review was performed to evaluate the U.S. Steel Irvin facility. The case-by-case RACT Control Options for U.S. Steel Irvin are detailed in Table 5 (NO\(_X\)) and Table 6 (VOC).

Table 5  
RACT NO\(_X\) Control Comparisons

<table>
<thead>
<tr>
<th>Control Option</th>
<th>P001 Reheat Furnaces</th>
<th>P015 Coke Oven Gas Flares</th>
<th>B001</th>
<th>B002</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
</tr>
<tr>
<td>Low Nox Burners</td>
<td>tpy NO(_X) Removed</td>
<td>129</td>
<td>14</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>1,077,006</td>
<td>115,443</td>
<td>123,062</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$8,300</td>
<td>8,300</td>
<td>8,200</td>
</tr>
<tr>
<td>Ultra Low NO(_X) Burners</td>
<td>tpy NO(_X) Removed</td>
<td>58.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>$715,700</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$12,300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flue Gas Recirculation / Over-fire Air</td>
<td>tpy NO(_X) Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FGR/OFR + LNB</td>
<td>tpy NO(_X) Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low Excess Air</td>
<td>tpy NO(_X) Removed</td>
<td>Technically Infeasible</td>
<td>Previously Implemented</td>
<td>Previously Implemented</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>Technically Infeasible</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>Technically Infeasible</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Selective Catalytic Reduction</td>
<td>tpy NO(_X) Removed</td>
<td>90.5</td>
<td>50.3</td>
<td>53.4</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>3,268,500</td>
<td>981,700</td>
<td>1,034,300</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$36,100</td>
<td>19,500</td>
<td>19,400</td>
</tr>
<tr>
<td>Selective Non-Catalytic Reduction</td>
<td>tpy NO(_X) Removed</td>
<td>45.2</td>
<td>25.2</td>
<td>26.7</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>$14,450,100</td>
<td>110,300</td>
<td>3,262,700</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$319,700</td>
<td>123,600</td>
<td>122,300</td>
</tr>
<tr>
<td>Combustion / Performance Optimization</td>
<td>tpy NO(_X) Removed</td>
<td>Previously Implemented</td>
<td>1.1</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>Cost</td>
<td>$6,500</td>
<td>0</td>
<td>2,000</td>
</tr>
<tr>
<td></td>
<td>$/ton</td>
<td>$1,000</td>
<td>N/A</td>
<td>1,800</td>
</tr>
<tr>
<td></td>
<td>Abatement Factor</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Control Option</td>
<td>P001 Reheat Furnaces</td>
<td>P008 Cold Reduction Mill</td>
<td>P015 Coke Oven Gas Flares</td>
<td>B001</td>
</tr>
<tr>
<td>--------------------------------------</td>
<td>----------------------</td>
<td>--------------------------</td>
<td>---------------------------</td>
<td>------</td>
</tr>
<tr>
<td><strong>Combustion Fuel</strong></td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
<td>Coke Oven Gas</td>
</tr>
<tr>
<td><strong>Flare Minimization Plan</strong></td>
<td>tpy NO\textsubscript{x} Removed</td>
<td>Previously Implemented</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cost</strong></td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>$/ton</strong></td>
<td>N/A</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 6** RACT VOC Control Comparisons

<table>
<thead>
<tr>
<th>Control Option</th>
<th>P001 Reheat Furnaces</th>
<th>P008 Cold Reduction Mill</th>
<th>P015 Coke Oven Gas Flares</th>
<th>F002 Solvents Parts Cleaning</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Combustion Fuel</strong></td>
<td>Coke Oven Gas</td>
<td>None</td>
<td>Coke Oven Gas</td>
<td>None</td>
</tr>
<tr>
<td><strong>Thermal Oxidation</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td>Technically Infeasible</td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>Cost</strong></td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>$/ton</strong></td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
<td>Technically Infeasible</td>
</tr>
<tr>
<td><strong>Carbon Adsorption</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Routing to a Boiler</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Routing to a Flare</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Condensers</strong></td>
<td>tpy VOC Removed</td>
<td>Technically Infeasible</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Combustion / Performance Optimization</strong></td>
<td>tpy VOC Removed</td>
<td>Previously Implemented</td>
<td>Previously Implemented</td>
<td>Previously Implemented</td>
</tr>
<tr>
<td><strong>Cost</strong></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>$/ton</strong></td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Mist Eliminator</strong></td>
<td>tpy VOC Removed</td>
<td>Previously Implemented</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Flare Minimization Plan</strong></td>
<td>tpy VOC Removed</td>
<td></td>
<td>Previously Implemented</td>
<td></td>
</tr>
<tr>
<td><strong>Low-Volatility Solvents</strong></td>
<td>tpy VOC Removed</td>
<td></td>
<td>Technically Infeasible</td>
<td></td>
</tr>
<tr>
<td><strong>Oil Substitution</strong></td>
<td>tpy VOC Removed</td>
<td></td>
<td>Technically Infeasible</td>
<td></td>
</tr>
</tbody>
</table>
Identified Control Options

The following control options were identified for the Irvin case-by-case RACT analysis:

**Reheat Furnaces – NOx Control**

- **Low Excess Air (LEA)** - The steel making equipment (i.e. reheat and annealing furnaces) at U.S Steel – Irvin Plant are direct-fired sources and not typically amenable to substantive oxygen control. Furthermore, although the EPA’s Alternative Control Techniques Document for Iron and Steel Mills (ACT) reports the use of LEA for reheat furnaces, it only provides an instance for a single reheat furnace in a retrofit application, wherein the emissions reductions achieved were only 14% and these emissions reductions are not considered substantive for control. Due to these issues, LEA is not considered to be technically feasible.

- **Low NOx Burners (LNBs)** – LNBs have been previously installed in reheat furnaces at other facilities, but usually as part of a new furnace unit and combusting natural gas instead of coke oven gas as with Irvin’s reheat furnaces. In the case of retrofits, such as Irvin, results have been mixed with product quality being affected by the degree of NOx reduction and in some cases, the actual NOx emission reductions being less than indicated in the RACT/BACT/LAER Clearinghouse Database and thus the cost of emission reductions per ton to be greater than expected. When taking the previous factors into consideration, and especially the predominant usage of coke oven gas, LNBs are determined to not be economically feasible.

- **Flue gas recirculation (FGR)** – The reheat furnaces already use a portion of the exhaust stream for preheating so FGR has already been implemented in some manner. Additional FGR could be possible, no vendors were identified that would provide guarantees since FGR could affect product quality due to changes in oxygen content.

- **Over-fire air (OFA)** – Overfire air is considered to be technologically infeasible since this technology typically only works in equipment designed for contained combustion. Steel making equipment, including reheat furnaces are direct fired sources and not typically amenable to substantive excess oxygen control.

- **Selective catalytic recirculation (SCR)** – SCR has been previously installed in reheat furnaces and there was a reduction in NOx emissions, but significant issues included not achieving expected NOx reductions, rapid catalyst degradation, ammonia slip issues, exhaust heat variations, flow rate issues, gas composition issues, and oxygen content issues. SCR was considered to be technically feasible, but due to the issues listed and the high expected cost, SCR is not considered to be economically feasible.

- **Selective non-catalytic reduction (SNCR)** – In a review of the literature, there are currently no known selective non-catalytic reduction installations at iron and steel plants. Additionally, SNCR would face the same major issues as SCR (above) and thus is not considered to be an economically feasible option.

- **Combustion optimization / tune-up** – This technology is technologically and economically feasible and has been previously implemented at the Irvin reheat furnaces.

**Reheat Furnaces – VOC Control**

- **Thermal oxidation (TO)** – Thermal oxidation to control VOCs is not technically feasible due to the low VOC concentrations (less than 0.4 ppm) in the exhaust stream.

- **Carbon adsorption** – Carbon adsorption is only feasible at concentrations equal to or greater than 1000 ppm, but the VOC concentrations in the exhaust stream are less than 0.4 ppm and thus technically infeasible.
• **Routing to a boiler** – The boilers at Irvin have operating temperatures of approximately 700°F, which is too low to measurably reduce VOC concentrations and thus this option is technically infeasible.

• **Routing to a flare** – Routing to the four flares at Irvin are not expected to measurably reduce VOC concentrations and thus are technically infeasible.

• **Condensers** – A condenser requires the inlet stream to have a VOC concentration of at least 5,000 PPM and since the VOC concentration in the reheat furnaces’ waste stream is less than 0.4 ppm, this control option is technically infeasible.

• **Combustion optimization / tune-up** - This technology is technologically and economically feasible and has been previously implemented at the Irvin reheat furnaces.

**Coke Oven Gas Flares - NOx Control**

The flame is not enclosed so add-on controls are not available.

• **Good engineering practices** – This option is already implemented industry-wide.

• **Flare minimization plan** – This option is technically and economically feasible and has been previously implemented.

**Coke Oven Gas Flares - VOC Control**

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 VOC. In general, reductions of VOC emissions from flares are based on good engineering practices and on minimization of fuel burned.

• **Good engineering practices** - This option is already implemented industry-wide.

• **Flare minimization plan** - This option is technically and economically feasible and has been previously implemented.

**Boilers 001 and 002 – NOx Control**

• **Low NOx burners (LNBs)** – LNBs were analyzed for cost effectiveness through a direct vendor quotation and the quotation received indicated that a 25% reduction in NOx emissions is achievable compared to baseline potential boiler NOx emissions of 0.16 lbs.MMBtu. Based on the economic analysis, this option is not economically feasible.

• **Selective catalytic recirculation (SCR)**- SCR units typically require at least 10% excess air to effectively reduce NOx below 10% since below this value the reduction becomes unstable. However, in the case of Irvin, the excess air is less than 5% resulting in lower expected efficiency.

• **Selective non-catalytic reduction** – Based on the economic analysis, this option is not economically feasible.

• **Low Excess Air** – This option has been previously implemented

• **Tune-up** – This option has been previously implemented

**Cold Reduction Mill – VOC Control**

• **Mist eliminators** – The facility is currently using this technology and no further emission reductions are anticipated.
• Thermal oxidizer – A thermal oxidizer is not considered to be technically feasible for the cold reduction mill since the majority of the mist from the operation is water resulting in the thermal oxidizer needing to be significantly large to control the operation. Additionally, the VOC concentration is the exhaust stream is less than 4 ppm, which is too low to consistently control.

• Oil substitution – Oil substitution for the cold reduction mill is not considered to be technically feasible since an oil with a lower VOC content cannot be identified that can be applied to the cold reduction mill and offer the same product quality performance.

Solvents Parts Cleaning – VOC Control

• Use of low-volatility solvents – The solvents currently used by the Irvin plant have been determined to be the lowest volatility available without sacrificing quality and thus this option is considered to be technically infeasible.

• Operating practices – The Irvin plant is currently meeting the operating practices specified in §2105.15 and thus is meeting RACT.

V. RACT Emissions Requirements

Based on the findings in this RACT analysis, the U.S. Steel Irvin facility emissions can be summarized as follows:

<table>
<thead>
<tr>
<th>Table 7</th>
<th>RACT II Emission Reduction Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NOx Potential Emissions (tpy)</strong></td>
<td></td>
</tr>
<tr>
<td>Current PTE</td>
<td>RACT Reduction</td>
</tr>
<tr>
<td>1,861</td>
<td>0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 8</th>
<th>All RACT I and RACT II Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit ID</td>
<td>Emissions Unit</td>
</tr>
<tr>
<td>P001</td>
<td>80-inch hot strip mill, five reheat furnaces</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>P002</td>
<td>64” continuous coil HCL pickle</td>
</tr>
<tr>
<td>P007</td>
<td>84” continuous pickle line</td>
</tr>
<tr>
<td>P008</td>
<td>no. 3 five stand cold reduction mill</td>
</tr>
<tr>
<td>P009</td>
<td>Thirty-one HPH annealing furnaces</td>
</tr>
<tr>
<td>Unit ID</td>
<td>Emissions Unit</td>
</tr>
<tr>
<td>---------</td>
<td>----------------</td>
</tr>
<tr>
<td>P010</td>
<td>open coil annealing furnaces</td>
</tr>
</tbody>
</table>
| P011    | continuous annealing | • Good combustion and air pollution control practices  
• Annual combustion process adjustment | • Biennial tune-up |
| P012    | no. 1 continuous galvanizing line | • Good combustion and air pollution control practices | • 0.10 lb NOx/MBtu |
| P013    | no. 2 continuous galvanizing lines | • Good combustion and air pollution control practices | • Good operating practices and manufacturers’ specifications |
| P015    | coke oven gas flares | • None | • Flare minimization plan |
| B001    | Boiler no. 1 | • Good combustion and air pollution control practices  
• Annual combustion process adjustment | • Low excess air  
• Combustion optimization |
| B002    | Boiler no. 2 | • Good combustion and air pollution control practices  
• Annual combustion process adjustment | • Low excess air  
• Combustion optimization |
| B003    | Boiler no. 3 | • Good combustion and air pollution control practices  
• Annual combustion process adjustment | • Biennial tune-up |
| B004    | Boiler no. 4 | • Good combustion and air pollution control practices  
• Annual combustion process adjustment | • Biennial tune-up |
| F001    | Fugitive Road Emissions | • None | • Exempt |
| F002    | Solvents parts cleaning | • None | • Already subject to Article XXI RACT |

As shown in Table 7 and Table 8, the RACT conditions have already been implemented in previous ACHD air quality permits resulting in no emission reduction at the U.S. Steel Irvin facility for this particular RACT analysis.

VI. New and Revised RACT II IP/OP Permit Conditions

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Description</th>
<th>Permit Condition 0050a</th>
<th>RACT II Regulations</th>
</tr>
</thead>
</table>
| P001      | 80-inch hot strip mill, five reheat furnaces | Condition V.A.1.e  
Condition V.A.4.a  
Condition V.A.4.b  
Condition V.A.4.c | 25 PA Code §129.99  
25 PA Code §129.100  
25 PA Code §129.100  
25 PA Code §129.100 |
<table>
<thead>
<tr>
<th>Source ID</th>
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<th>Permit Condition 0050a</th>
<th>RACT II Regulations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Condition V.A.4.c</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.A.4.d</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.A.6.a</td>
<td>25 PA Code §129.99</td>
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<tr>
<td>P008</td>
<td>Cold Reduction Mill</td>
<td>Condition V.D.1.d</td>
<td>25 PA Code §129.99</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.D.4.b</td>
<td>25 PA Code §129.100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Condition V.D.4.d</td>
<td>25 PA Code §129.100</td>
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<td></td>
<td></td>
<td>Condition V.D.6.a</td>
<td>25 PA Code §129.99</td>
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<tr>
<td>P015</td>
<td>Coke Oven Gas Flares</td>
<td>Condition V.J.1.a</td>
<td>25 PA Code §129.99</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.J.4.a</td>
<td>25 PA Code §129.100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Condition V.J.4.b</td>
<td>25 PA Code §129.100</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler 1</td>
<td>Condition V.K.4.a</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.K.4.c</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.K.6.a</td>
<td>25 PA Code §129.99</td>
</tr>
<tr>
<td>B002</td>
<td>Boiler 2</td>
<td>Condition V.L.4.a</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.L.4.a</td>
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<td>25 PA Code §129.99</td>
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<tr>
<td>F002</td>
<td>Solvents Parts Cleaning</td>
<td>Condition V.P.1.d</td>
<td>25 PA Code §129.99</td>
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<td></td>
<td>Condition V.P.1.e</td>
<td>25 PA Code §129.100</td>
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<td>Condition V.P.4.a</td>
<td>25 PA Code §129.100</td>
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<tr>
<td></td>
<td></td>
<td>Condition V.P.4.b</td>
<td>25 PA Code §129.100</td>
</tr>
</tbody>
</table>

All other RACT monitoring, recordkeeping and reporting requirements applicable to case-by-case RACT II determination have already been included in previous ACHD air quality permits.

1 The 2018 heat content for the COG is 539.7 btu/ft³ = 539.7 MMBtu/MMcf
2 EPA performed flare studies as part of development of new source performance standards for refineries (40 CFR 60, Subpart J) in 2012.
3 The 2018 heat content for the COG is 539.7 btu/ft³ = 539.7 MMBtu/MMcf
4 For P012 (continuous galvanizing line) Maximum NOX emissions under presumptive RACT (§129.97(g)(1)) are: (0.10 lb NOX/MMBtu)*(50 MMBtu/hr)*(8760 hrs/yr)*(1 ton/2000 lbs) = 21.9 tons/yr. Thus, P012 meets presumptive RACT
5 Condition V.H.1.c of Operating Permit 0050a (table V-H-1) issued on June 21, 2019 limits NOX emissions to 0.06 lb/MBtu. This value is not explicitly stated, but given that the boiler is rated at 50 MMBtu/hr and the limit is 13.14 tons/yr, this is equal to 0.06 lb/MBtu.
Source Information

Source Name: U.S. Steel Mon Valley Works – Irvin Plant  
Source Location: Camp Hollow Road, West Mifflin, PA 15222  
Mailing Address: P. O. Box 878, Dravosburg, PA 15122  
County: Allegheny  
SIC Code: 3312 (Steel Works, Blast Furnaces (Including Coke Ovens), and Rolling Mills)  
Part 70 Permit No.: 0050  
Major Source: NOx and VOC  
Permit Reviewer: ERG/TC  

The Allegheny County Health Department (ACHD), Office of Air Quality (OAQ) has performed the following RACT (Reasonably Available Control Technology (RACT)) analyses for a major source of NOx and VOC relating to a secondary steel processing facility, located in West Mifflin, Pennsylvania.

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 for EPA approval. As such, Allegheny County must reevaluate 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 State Implementation Plan (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 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. The manual and spreadsheets may be found on the CATC/RBLC web page on EPA’s Technology Transfer Network (TTN) at http://www.epa.gov/ttn/catc/.

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)

**Source/Process Description**

U.S. Steel Mon Valley Works – Irvin Plant, located at Camp Hollow Road in West Mifflin, PA, is a secondary steel processing facility that receives and finishes steel slabs. Emissions from the source are primarily the result of natural gas/coke oven gas combustion from furnaces, flares, and boilers to support hot and cold rolling, continuous pickling, annealing, galvanizing, and terne coating operations. Detailed descriptions of the relevant emissions units are provided in the following sections.

The VOC and NOx emitting emission units at the plant are described in Table 1. Units for which a VOC or NOx RACT Evaluation is included in this document are identified accordingly.
### Table 1. Emission Units Emitting VOC and NOx

<table>
<thead>
<tr>
<th>UNIT</th>
<th>SIZE</th>
<th>NUMBER OF UNITS</th>
<th>FUEL/RAW MATERIAL</th>
<th>CONTROL DEVICE(S)</th>
<th>NOx</th>
<th>VOC</th>
</tr>
</thead>
<tbody>
<tr>
<td>80-inch Hot Strip Mill Reheat Furnace [P001-P005]</td>
<td>140 MMBtu/hr</td>
<td>5</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>80-inch Hot Strip Mill Roughing and Finishing Mill [P016]</td>
<td>3000000 tons/yr</td>
<td>1</td>
<td>Steel Slabs and Rolling Oil Solution</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>No.3 Five Stand Cold Reduction Mill [P008]</td>
<td>2500000 tons/yr</td>
<td>1</td>
<td>Steel Coils and Rolling Oil Solution</td>
<td>Cyclonic Mist Eliminator</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>HPH Annealing Furnaces with coke oven gas enriched with natural gas [P009]</td>
<td>4.9 MMBtu/hr</td>
<td>31</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Open coil annealing furnace [P010 - Nos. 1-9]</td>
<td>7.2 MMBtu/hr</td>
<td>9</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Open coil annealing furnace [P010 - Nos. 10-13]</td>
<td>9 MMBtu/hr</td>
<td>4</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Open coil annealing furnace [P010 - No. 14]</td>
<td>5.4 MMBtu/hr</td>
<td>1</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Open coil annealing furnace [P010 - No.15 and 16]</td>
<td>7.47 MMBtu/hr</td>
<td>2</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Continuous Annealing furnace [ P011]</td>
<td>45 MMBtu/hr</td>
<td>1</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>No.1 Continuous Galvanizing Line preheat furnace [P012]</td>
<td>50 MMBtu/hr</td>
<td>1</td>
<td>Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>No.1 Continuous Galvanizing Line galvanneal furnace [P012]</td>
<td>18 MMBtu/hr</td>
<td>1</td>
<td>Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>No.2 Continuous Galvanizing &amp; Aluminum Coating Lines, preheat furnace [P013]</td>
<td>18 MMBtu/hr</td>
<td>1</td>
<td>Natural Gas</td>
<td>None</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Continuous Terne Line, natural gas-fired lead melt pot heater [P014]</td>
<td>10 MMBtu/hr</td>
<td>1</td>
<td>Steel Coils, Natural Gas, Acid, Lead, Flux, Nickel Solution Treatment Chemicals, Caustic Solution, Coating Oil</td>
<td>Granet type packed bed scrubber</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coke oven gas flares [P015 - No.1 to No.3 and the Peachtree Flare]</td>
<td>6750000 ft³/day</td>
<td>4</td>
<td>Coke Oven Gas</td>
<td>None</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>
Natural gas and coke oven fired boiler [B001] 79.8 MMBtu/hr 1 Coke Oven Gas and Natural Gas None ✓

Natural gas and coke oven fired boiler [B002] 84.6 MMBtu/hr 1 Coke Oven Gas and Natural Gas None ✓

Natural gas and coke oven fired boiler [B003 and B004] 41.6 MMBtu/hr 2 Coke Oven Gas and Natural Gas None ✓

Space heaters 160 MMBtu/hr combined Various Natural Gas None

Solvent parts cleaning - cold cleaning [F002] 160 MMBtu/hr combined Various Natural Gas Self-contained/Covered ✓

### RACT Analyses in this Document

This source is a major source of NOx and VOC; therefore RACT analyses for NOx and VOC have been conducted and are provided in this document. The table in the previous section identifies which emission units are included in the RACT analyses for VOC and NOx in this document.

For units for which a RACT evaluation is not identified in the table, ACHD has determined that a RACT evaluation for the identified pollutant(s) is not required. These units and the reasons for which a RACT evaluation is not included for the identified pollutant(s) are as follows:

1) ACHD has determined that it is not necessary to conduct a VOC RACT evaluation for the following emission units:
   - Continuous Terne Line, Natural gas-fired lead melt pot heater (P014)
   - Space heaters
   - Open coil annealing furnace, natural gas/coke oven fired [P010 - Nos. 1-9]
   - Open coil annealing furnace, natural gas/coke oven fired [P010 - Nos. 10-13]
   - Open coil annealing furnace, natural gas/coke oven fired [P010 - No. 14]
   - Open coil annealing furnace, natural gas/coke oven fired [P010 - Nos. 15-16]
   - Continuous Annealing furnace, natural gas/coke oven fired [P011]
   - No.1 Continuous Galvanizing Line, natural gas-fired galvanneal furnace [P012]
   - No.1 Continuous Galvanizing Line preheat furnace [P012];
   - No.2 Continuous Galvanizing & Aluminum Coating Lines, natural gas preheat furnace [P013]
   - Four (4) natural gas and coke oven fired boilers [B001, B002, B003, B004]

2) ACHD has also determined that it is not necessary to conduct a NOx RACT evaluation for the following emission units:
   - Continuous Terne Line, Natural gas-fired lead melt pot heater (P014)
   - Space heaters

These decisions were made based on the relatively low potential emissions of the pollutants identified from these units. ACHD considers it unlikely that additional controls would be technically and economically feasible for these units for the identified pollutants.

The remaining units at the source, for which a RACT evaluation has been identified in the table and included in this document, consist of numerous emission units comprising of
coke oven and natural gas-fired furnaces, natural gas-fired preheaters, mills, coke oven gas flares, boilers, and fugitive VOC emissions. Where possible, emission units of similar type and function have been grouped together for the purposes of conducting VOC and/or NOx RACT analyses. Specifically, a NOx analysis has been conducted separately for:

A. Five (5) 80-inch Hot Strip Mill Reheat Furnaces [P001-P005];
B. Coke oven and natural gas-fired furnaces, including: Thirty-one (31) HPH Annealing Furnaces [P009], sixteen (16) open coil annealing furnaces [P010], and one (1) Continuous Annealing Furnace [P011];
C. Natural gas-fired furnaces, including: one (1) No.1 Continuous Galvanizing Line preheat furnace [P012], one (1) No.1 Continuous Galvanizing & Aluminum Coating Lines, preheat furnace; and one (1) No.2 Continuous Galvanizing & Aluminum Coating Lines, preheat furnace;
D. Coke oven gas flares [P015 - No.1 to No.3 and the Peachtree Flare]
E. Four (4) natural gas and coke oven fired boilers [B001, B002, B003, B004];

A VOC analysis has been conducted separately for:
F. Five (5) 80-inch Hot Strip Mill Reheat Furnaces [P001-P005];
G. 80-inch Hot Strip Mill Roughing and Finishing Mill [P016] and No.3 Five Stand Cold Reduction Mill [P008];
H. Coke oven and natural gas-fired furnaces, including: Thirty-one (31) HPH Annealing Furnaces [P009];
I. Coke oven gas flares [P015 - No.1 to No.3 and the Peachtree Flare]
J. Solvent parts cleaning - cold cleaning [G002]

**A. RACT for NOx – Five (5) 140 MMBtu/hr 80-inch Hot Strip Mill Reheat Furnaces [P001-P005]**

Five (5) identical direct-fired reheat furnaces used to reheat incoming slabs prior to hot rolling on the scale breaking/roughing and finishing mill stands; each rated at 140 MMBtu/hr fuel input and capable of processing 3,000,000 tons of sheet per year. The furnaces are fired with natural gas-enriched coke oven gas, which is piped in from a nearby coke production facility (U.S. Steel - Clairton Works); emissions exhaust to stacks SP1 through SP6. Emissions are uncontrolled.

The slab enters the furnace traveling vertically through the three heating zones. The Zone 1 (soak), zone 2 (top) and zone 3 (bottom) have 8, 6, and 6 burners, respectively. Temperatures within the furnace range from 1,800 - 2,400°F. Metallurgy and slab quality are highly affected by the burner flame length, temperature and distribution; too much causes scaling, too little causes stress issues.

The Title V operating permit, condition V.A.1.a, states that "Only coke oven gas and natural gas shall be combusted in reheat furnaces No. 1 through No. 5." [§2103.12.h.5.D].

It should also be noted that the Title V operating permit, condition V.A.1.g, states that NOx emissions from the Hot Strip Mill Reheat Furnaces No. 1 through No. 5 shall not exceed 39.20 lb/hr when combusting coke oven gas and 50.26 lb/hr when combusting natural gas. Total annual emissions are limited to 220.14 tons per year.

**Step 1 – Identify Control Options**

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the Hot Strip Mill Reheat Furnaces and consulted several references to ensure that all possible control options were identified.
ACHD reviewed EPA’s Alternative Control Techniques (ACT) Document for Iron and Steel Mills1 and the study “Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis”2 to determine if any other controls have been demonstrated since 1994 when the ACT was published. The identified controls are discussed below:

The ACT identifies the following controls for reheat furnaces:

1. Low Excess Air (LEA)
2. Low NOx Burners (LNB)
3. LNB + Flue Gas Recirculation (FGR)

U.S. Steel Irvin also identified the following control measures in their RACT submittal:

4. Ultra Low NOx Burners (ULNB)
5. FGR
6. Over-fire Air (OFA)
7. Selective Catalytic Reduction (SCR)
8. Selective Non-Catalytic Reduction (SNCR)
9. Regenerative Selective Catalytic Reduction (RSCR)
10. Combustion Optimization

No additional control measures were identified for reheat furnaces, except for combinations of controls listed above. These control measures have been organized into 6 groups: combustion optimization, staged combustion, additions to combustion air or fuel, low NOx burners, and post combustion controls.

**Combustion Optimization**

Furnace operation can be optimized to reduce NOx emissions by modifying furnace burner settings. For example, sources can specifically control the level of excess air to reduce NOx.

(a) **Combustion Optimization**

Combustion optimization involves an analysis to determine the combination of equipment settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the furnace. Combustion optimization includes conducting an evaluation of existing equipment, (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms and actuators to including oxygen probes, 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 furnace operation.

In boilers, performing combustion optimization can improve NOx emissions by 5 to 40 percent.3 The actual NOx emission rate achieved is dependent on the difference

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between the optimal settings and the furnace settings being used before optimization.

(b) **Low Excess Air (LEA)**

LEA is a burner optimization strategy in which the furnace is operated at the lowest excess air level that provides efficient, reliable, safe and complete combustion. In a reheat furnace application at a steel mini-mill, LEA resulted in a reduction of NOx emissions by 14%\(^4\) (in natural gas-fired units) and reduces the total flue gas flow and improves heat transfer. One notable advantage of this strategy is that no significant capital expenses for new or modified hardware are required.

The potential of LEA as a NOx control technique is limited by the onset of smoke or CO emissions. A number of other factors affect the excess air levels that can be implemented. These include the type of fuel fired, uniformity of the air/fuel ratio, air and fuel control lags during load swings, and other combustion control features such as staging of fuel or air. Although LEA is a feasible technique for furnaces, the trend in NOx control for these sources has been in improved burner design.\(^5\)

**Staged Combustion**

Staged combustion includes air staging to delay combustion and lower flame temperatures.

(c) **Over-fire Air**

In a conventional furnace, all of the air required for combustion is supplied through the burners. Over-fire air (OFA) is an alternate combustion design in which the burners are fired more fuel-rich than normal, and the additional air needed to complete combustion is admitted through overfire air ports or an idle top row of burners. This causes a staged combustion of the fuel: the air flow routed directly to the burners is reduced to promote fuel rich combustion in the primary (i.e. flame) combustion zone. The subsequent and secondary air flow - the overfire air - completes the combustion process. This design reduces NOx emissions in two ways. First and foremost, the staged configuration delays the combustion process and consequently lowers the flame temperature which suppresses thermal NOx formation. Second, the relatively low O2 levels in the combustion zone inhibits fuel NOx formation.

OFA serves as a both a "stand-alone" approach and one that is paired with other control options such as LNB. It can be used with nearly any fuel and most combustion systems. In emissions tests on utility boilers, OFA has achieved average NOx reductions of 24-59 percent with oil, coal, and natural gas firing compared with baseline levels.\(^6\)

OFA is more easily implement on large, utility scale boilers than on smaller units and furnaces. Space for additional ductwork, furnace penetrations, and fans may be a problem if these additions are needed. These factors are potential impediments to implementing OFA techniques in iron and steel process facility furnaces, especially on retrofit basis.

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\(^5\) Id.

\(^6\) Id.
Additions to Combustion Air or Fuel

Furnace operation can be optimized to reduce NOx emissions by injecting flue gases or other materials into the combustion zone. This controls the formation of NOx by controlling the stoichiometric ratio of the chemicals that react to form NOx. The addition of flue gas dilutes the combustion zone and reduces the combustion temperature, which in turn reduces the formation of thermal NOx.

(d) Flue Gas Recirculation

As the name suggests, flue gas recirculation (FGR) involves the recirculation of a portion - typically 20-30% - of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. FGR can be classified into two types; external or induced. External FGR utilizes an external fan to recirculate the flue gases, and external piping routes the exhaust gases from the stack to the burner. Induced FGR utilizes the combustion air fan within the unit to recirculate the flue gases. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are premixed with the combustion air and introduced into the flame through the burner.

From a strictly technical standpoint, FGR is feasible as long as there is no minimum operational temperature/oxygen requirement for the fuel fired emission unit. FGR may also affect fan capacity, furnace pressure, burner pressure drop, and turndown stability. If these are critical parameters for processes associated with iron and steel production, then FGR may be infeasible.

NOx reductions vary considerably depending on the type of fuel. When operated without additional controls, the normal NOx control efficiency range for FGR used in a furnace is 30-50%. When used in conjunction with LNB, FGR is capable of reducing NOx emissions by 50-72%.7

Low NOx Burners

Low NOx burners work to reduce NOx emissions by controlling the stages of combustion, lowering combustion zone temperatures to reduce the production of NOx.

(e) Low NOx Burners

Low NOx Burners (LNB) is a relative term that refers to a burner design in which the supplied fuel and air are staged across the burner. The staging results in fuel-lean and fuel-rich combustion zones in the furnace at the burner. In the fuel-lean zones, the combustion temperature is lowered, reducing the production of NOx emissions. Both the temperature and oxygen concentrations are lowered in the fuel-rich zones. LNB technology is available from many manufacturers and applicable to all fuels. Retrofitting older furnaces with newer LNB can be technically feasible, but comes at a high capital cost.

The estimated NOx control efficiency for LNBs in high temperature applications, such as a reheat furnace, is 25%. However when coupled with FGR or selective non-

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catalytic reduction (SNCR) these efficiencies increase to 50-72 and 50-89%, respectively.  

(f) **Ultra Low NOx Burners**

Specific to natural gas fired units, Ultra Low NOx Burners (ULNB) generally refers to any advanced burner design that achieves NOx emissions from 2 - 9 ppm. These burners combine the benefits of flue gas recirculation and low-NOx burner control technologies. Rather than a system of fans and blowers (like FGR), the burner itself is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency. Because of this reduction in temperature, ULNB would likely only be applicable to processes at iron and steel plants that are not temperature dependent, unless the reduction in flame temperature doesn’t fall below the required threshold temperature for the process.

The estimated NOx control efficiency for ULNBs in high temperature applications is 50%. Newer designs have yielded efficiencies of between 75-85 percent. 

**Post Combustion Control**

Post combustion control includes the addition of technologies that reduce NOx emissions (as opposed to preventing NOx generation). Generally, these technologies include the addition of a catalyst or reactant into the exhaust stream which chemically reduces the NOx, allowing for removal from the gas stream.

(g) **Selective Catalytic Reduction**

Selective Catalytic Reduction (SCR) 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 with the following basic reaction pathways:

\[
\begin{align*}
4\text{NH}_3 + 4\text{NO} + \text{O}_2 & > 4\text{N}_2 + 6\text{H}_2\text{O} \\
8\text{NH}_3 + 6\text{NO}_2 & > 7\text{N}_2 + 12\text{H}_2\text{O}
\end{align*}
\]

The normal NOx control efficiency range for SCR is 70-90%. 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. Optimum NOx reduction occurs at catalyst bed temperatures of 600–750 °F for conventional (vanadium or titanium based catalysts), 470–510 °F for platinum catalysts, and 600–1000°F temperature range for a zeolite catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NOx molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth.

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8. *Id.*
10. *Id.*
Decreasing the space velocity (increasing catalyst bed depth) will improve NOx removal efficiency by increasing residence time, but will also cause an increase in catalyst bed pressure drop. Reaction temperature is also critical for proper SCR operation. Below the minimum temperature, reduction reactions will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NOx emissions.

SCR catalyst can be subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation, if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium.

SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the United States. There have been few uses of SCR in the iron and steel industry.

### Selective Non-Catalytic Reduction

Like SCR, SNCR operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires an exhaust of 1600-2100°F.

The normal NOx control efficiency range for SNCR is 40-70%.\(^{11}\) To date there are no known installations of SNCR at iron and steel plants.\(^{12}\)

### Regenerative Selective Catalytic Reduction (RSCR)

Regenerative Selective Catalytic Reduction (RSCR) is similar to SCR in that it operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. As noted above, SCR systems typically operate at approximately 600-750°F for the destruction of NOx. In some cases, a gas stream may be routed to particulate matter collection device or other control following exit of the furnace; in this case, the stream is significantly cooled, which may reduce the effectiveness of a catalyst. RSCR introduces a regenerative heater (similar to that used in a regenerative thermal oxidizer) prior to routing to an SCR. The temperature of the flue gas is temporarily elevated to improve catalyst performance, and the heat is recovered before sending the clean flue gas to the stack. These systems are primarily used for tail-end/low temperature applications where the flue gas is relatively cool, with low levels of particulates and acid gases. Such systems have been demonstrated to achieve a NOx reduction efficiency >80%, when applied to a cold gas (e.g., after boiler and scrubber/particulate removal equipment). It is currently applied in biomass plants for small boiler applications.\(^{13}\)

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Step 2 – Eliminate Technically Infeasible Control Options

A number of the control options identified are not technically feasible for controlling NOx emissions from the Hot Strip Mill Reheat Furnaces. A review of available controls identified low NOx burners, ultra low NOx burners, selective catalytic reduction, and selective non-catalytic reduction as technically feasible controls. This section presents the rationale explaining why each control option is, or is not, technically feasible.

(a) Combustion Optimization

Combustion optimization and operating and maintenance (O&M) practices are applicable to all types of furnaces combusting all types of fuels. Such practices are generally used throughout the industry to increase energy efficiency and lower fuel costs, as well as pollutant emissions. Currently, U.S. Steel – Irvin Plant is required to operate and maintain the Hot Strip Mill Reheat Furnaces in accordance with the good combustion and air pollution control practices, per RACT Order No. 258. Additionally, U.S. Steel – Irvin Plant is currently required to conduct an annual tune-up, including inspection, adjustment, cleaning, or necessary 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 inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation, per RACT Order No. 258. Although these requirements may not include all of the adjustments and optimizations that would be conducted during a full combustion optimization they would address several of the issues and make the emission reduction effectiveness of a full optimization even more uncertain. Therefore, combustion/performance optimization practices are considered technically feasible for the Hot Strip Mill Reheat Furnaces, but the additional emission reductions cannot be predicted and they would be expected to be relatively low since the source is already performing many of the optimization activities.

(b) Low Excess Air (LEA)

LEA involves operating the furnaces at the lowest excess air level that provides efficient, reliable, safe and complete combustion. The higher the excess air used for fuel combustion, the higher the potential NOx generation. Control of excess air used in the combustion process can typically only be performed in furnace equipment designed for contained combustion and/or staging of combustion, such as indirect fired equipment with chambers or windboxes. The steel making equipment (i.e. reheat and annealing furnaces) at U.S Steel – Irvin Plant are direct-fired sources and not typically amenable to substantive excess oxygen control. Furthermore, although the ACT for Iron and Steel Mills reports the use of LEA for reheat furnaces, it only provides an instance for a single reheat furnace in a retrofit application, wherein the emissions reductions achieved were only 14%. These emissions reductions are not considered substantive for control. The ACT further noted that another control option would likely have been preferred for this source.14

Due to these issues, the use of LEA is not considered a technologically feasible option for the Hot Strip Mill Reheat Furnaces.

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(c) **Over-fire Air**

Over-fire air (OFA) is a combustion design in which a controlled portion of the combustion air flow is diverted to injection ports beyond the last row of burners. As with LEA, 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. Steel making equipment (i.e. reheat and annealing furnaces) are direct fired sources and not typically amenable to substantive excess oxygen control. Due to these issues, the use of over-fire air is not considered a technologically feasible option for the Hot Strip Mill Reheat Furnaces.

(d) **Flue Gas Recirculation**

FGR involves the recirculation of a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. Although the ACT for Iron and Steel Mills considers the use of LNB plus FGR, the ACT provides that FGR has principally been applied to boilers and process heaters, and only reports use of LNB plus FGR controls for two reheat furnaces.\(^\text{15}\)

The reheat furnaces at U.S. Steel – Irvin Plant currently reuse a portion of the exhaust stream for preheating, therefore, FGR is already performed in some manner. Additional FGR may be possible; however, the oxygen content provided in each zone of the furnaces can have a significant effect on product quality (due to changes in temperature at the flame tip/slab interface). Additionally, vendors for FGR were unable to provide specific estimates of potential NOx reductions without performing detailed studies on the specific furnaces, which use coke oven gas. Therefore, FGR is not considered a technologically feasible option for the Hot Strip Mill Reheat Furnaces.

(e) **Low NOx Burners**

LNB technology is available from many manufacturers and applicable to all fuels, including coke oven gas. Low NOx burners (LNBs) have previously been installed in reheat furnaces, including other U.S. Steel facilities (e.g., U.S. Steel Granite City facility in Granite City, Illinois), usually as part of a new furnace unit. Existing furnaces have also been retrofitted with LNBs. LNBs have been shown to be effective in reducing NOx emissions in reheat furnaces, both new and retrofitted. Therefore, LNBs are considered technically feasible for the Hot Strip Mill Reheat Furnaces.

(f) **Ultra Low NOx Burners**

Ultra Low NOx burners (ULNBs) have previously been installed in reheat furnaces, including other U.S. Steel facilities (e.g., U.S. Steel Granite City facility in Granite City, Illinois), usually as part of a new furnace unit. Existing furnaces have also been retrofitted with ULNBs. ULNBs have been shown to be effective in reducing NOx emissions in reheat furnaces, both new and retrofitted. Therefore, ULNBs are considered technically feasible for the Hot Strip Mill Reheat Furnaces.

(g) **Selective Catalytic Reduction**

SCR controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. SCR units have been used on slab furnaces that are similar to the Hot Strip Mill Reheat Furnaces in similar facilities in

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\(^{15}\) *Id.*
the United States. SCR applications in slab furnaces in the United States have resulted in a reduction of NOx emissions, however, these reductions are not consistent from facility to facility. Additionally, the use of SCR in reheat furnaces has resulted in degrading of the SCR system very quickly (i.e., frequent catalyst damage). Ammonia slip has also been a problem. Exhaust heat variations, flow rates, gas composition, and oxygen content all present issues in the operation of an SCR on a reheat furnace. With these considerations, SCR is considered to be technically feasible for the Hot Strip Mill Reheat Furnaces.

### (h) Selective Non-Catalytic Reduction

SNCR is similar to SCR, but it does not use a catalyst. SNCR has not been used on slab furnaces such as reheat furnaces in the United States. As with SCR, exhaust heat variations, flow rates, gas composition, and oxygen content are expected to present issues in the operation of an SNCR on a reheat furnace. With these considerations, SNCR is considered to be technically feasible for the Hot Strip Mill Reheat Furnaces.

### (i) Regenerative Selective Catalytic Reduction (RSCR)

RSCR is similar to SCR but introduces a regenerative heater to elevate the temperature of flue gas to improve catalyst performance, and heat is recovered before sending the clean flue gas to the stack. RSCR has the ability to use the majority of heat which is lost to the stack, and therefore requires significantly less additional fuel use than other technologies. RSCR has not been used on slab furnaces such as reheat furnaces in the United States. Instead, this technology has largely been used at biomass plants in small boiler applications. Extensive research and pilot testing are needed to determine whether this technology is feasible for large coke oven gas fired furnaces. Additionally, extensive rerouting of ductwork would be required. For this reason, RSCR is not considered to be technically feasible for the Hot Strip Mill Reheat Furnaces at this time.

### Step 3 - Evaluate Control Options

#### Emissions and Emission Reductions

The five 80-inch Hot Strip Mill Reheat Furnaces have a combined potential to emit 1100.69 tpy NOx, as calculated in the Title V Operating Permit No. 0050. Emissions from each furnace are limited to 220.14 tpy NOx [Condition V.A.1.g of Title V Permit No. #0050].

The technically feasible control options with their estimated control efficiency are as follows:

<table>
<thead>
<tr>
<th>Control Type</th>
<th>Estimated NOx Control Efficiency</th>
<th>Estimated NOx Emission Reductions (tons/yr/furnace)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNB</td>
<td>36%</td>
<td>79</td>
</tr>
<tr>
<td>ULNB</td>
<td>58%&lt;sup&gt;b&lt;/sup&gt;</td>
<td>129</td>
</tr>
<tr>
<td>SCR</td>
<td>80%&lt;sup&gt;c&lt;/sup&gt;</td>
<td>177</td>
</tr>
<tr>
<td>SNCR</td>
<td>45%&lt;sup&gt;d&lt;/sup&gt;</td>
<td>99</td>
</tr>
</tbody>
</table>

<sup>a</sup> A 1994 estimate from Bloom Engineering, Inc. indicated that Bloom 1440-series air staged LNBs would provide a NOx emissions reduction of 36% and an emission rate of 0.229 lb NOx/MMbtu.

<sup>b</sup> NOx efficiency based upon actual USS Granite City Limits for the same type of burners and same type of sources.
Economic Analysis

Using information provided by U.S Steel – Irvin Plant and collected by ACHD, a thorough economic analysis of the technically feasible control option for the five Hot Strip Mill Reheat Furnaces was conducted - see Appendix A for more information. The analysis estimates 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, except for direct installation costs, were calculated using the methodology described in Section 6, Chapter 1 of the “EPA Air Pollution Control Cost Manual, Sixth Edition” (document # EPA 452-02-001). Direct capital cost is based on a vendor quote. Annualized costs are based on an interest rate of 7% and an equipment life of 15 years for LNB and ULNB and 20 years for SCR and SNCR.

The basis of cost effectiveness, used to evaluate the control option, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost figures determined in the analysis is provided in the table below:

<table>
<thead>
<tr>
<th>Option</th>
<th>Total Capital Investment (TCI) ($/furnace)</th>
<th>Total Annualized Cost ($/yr/furnace)</th>
<th>Potential NOx removal from add-on control (ton/yr/furnace)</th>
<th>Cost Effectiveness ($/ton NOx removed/furnace)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNB</td>
<td>$991,096b</td>
<td>$108,817c</td>
<td>79</td>
<td>$1,373</td>
</tr>
<tr>
<td>ULNB</td>
<td>$4,966,054a</td>
<td>$715,690</td>
<td>129</td>
<td>$5,558</td>
</tr>
<tr>
<td>SCR</td>
<td>$4,463,230</td>
<td>$3,250,123</td>
<td>177</td>
<td>$18,404</td>
</tr>
<tr>
<td>SNCR</td>
<td>$1,563,936</td>
<td>$14,450,079</td>
<td>99</td>
<td>$145,463</td>
</tr>
</tbody>
</table>

\(^a\) Costs and potential NOx removal provided on a per furnace basis.
\(^b\) Based on 1994 estimates for TCI for Bloom 1440-series air staged LNBs + installation of new fan, adjusted from 1994 dollars to 2014 dollars using the Chemical Engineering Plant Cost Index ($629,000 x 579.7/368.1 = $990,577)
\(^c\) Calculated using a capital recovery factor of 0.110 (based on a lifetime of 15 years and an interest rate of 7%) and the revised TCI ($990,578 x 0.110 = $108,963).

Step 4 – Select RACT

Based on the costs shown in Table 3, installing LNB is a cost effective NOx control option. The use of ULNB, SCR, or SNCR is much more costly.

ACHD reviewed the EPA’s RBLC determinations for similar reheat furnaces. Specifically, the ACHD reviewed 8 natural gas-fired reheat furnaces ranging between 130 MMBtu/hr and 471.8 MMBtu in size, representing 8 facilities, listed under the RBLC Code 81.290 (Other Steel Manufacturing Processes). Table 4 provides the RBLC findings.

ACHD considers the application of LNB meeting an emission rate of 0.229 lb/MMBtu to be considered RACT for the coke-oven gas fired Hot Strip Mill Reheat Furnaces. Although the RBLC reflects some reheat furnaces burning natural gas with a lower lb/MMBtu limit, the use of COG in the reheat furnaces is expected to produce a higher level of NOx.
### Table 4. Reheat Furnaces - RBLC Findings

<table>
<thead>
<tr>
<th>Source</th>
<th>RBLC ID</th>
<th>Date of Permit Issuance</th>
<th>NOx Limit (lb/MMBtu)</th>
<th>NOx Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nucor Steel Marion, Inc. [184 MMBtu/hr Natural Gas-Fired Reheat Furnace for Steel Billet]</td>
<td>OH-0341</td>
<td>12/23/2010</td>
<td>0.15 lb/MMBtu</td>
<td>LNB (PSD-BACT)</td>
</tr>
<tr>
<td>AK Steel Corporation [130 MMBtu/hr Natural Gas-Fired Slab Reheat Furnace]</td>
<td>OH-0331</td>
<td>1/11/2010</td>
<td>0.14 lb/MMBtu</td>
<td>-</td>
</tr>
<tr>
<td>Gerdau Ameristeel Wilton [145.5 MMBtu/hr Natural Gas-Fired Billet Reheat Furnace]</td>
<td>IA-0087</td>
<td>5/29/2007</td>
<td>110.23 lb/MMCF (0.11 lb/MMBtu)</td>
<td>ULNB (PSD-BACT)</td>
</tr>
<tr>
<td>Nucor Corporation [180 MMBtu/hr Natural Gas-Fired Reheat Furnace No. 2]</td>
<td>SC-0128</td>
<td>12/29/2006</td>
<td>0.075 lb/MMBtu</td>
<td>LNB (PSD-BACT)</td>
</tr>
<tr>
<td>V &amp; M Star [290 MMBtu/hr Natural Gas-Fired Billet Reheat Furnace]</td>
<td>OH-0316</td>
<td>9/23/2008</td>
<td>0.1 lb/MMBtu</td>
<td>ULNB (PSD-BACT)</td>
</tr>
<tr>
<td>Thyssenkrupp Steel and Stainless USA, LLC (4 -471.8 MMBtu/hr Natural Gas-Fired Walking Beam Reheat Furnaces)</td>
<td>AL-0230</td>
<td>8/17/2007</td>
<td>0.085 lb/MMBtu</td>
<td>ULNB (PSD-BACT)</td>
</tr>
<tr>
<td>Allegheny Ludlum [3 - 465 MMBtu/hr Natural Gas-Fired Walking Beam Reheat Furnaces]</td>
<td>PA-0274</td>
<td>2/16/2010</td>
<td>0.07 lb/MMBtu</td>
<td>ULNB (PSD-BACT)</td>
</tr>
<tr>
<td>Ipsco Steel [450 MMBtu/hr Natural Gas-Fired Reheat Furnace]</td>
<td>AL-0210</td>
<td>2/7/2005</td>
<td>0.172 lb/MMBtu</td>
<td>LNB (PSD-BACT)</td>
</tr>
</tbody>
</table>

Baseline emission rate | - | 2/18/2005 | 0.28 lb/MMBtu | - |

### B. RACT for NOx – Thirty-one (31) HPH Annealing Furnaces [P009], sixteen (16) open coil annealing furnaces [P010], and one (1) Continuous Annealing Furnace [P011]

This section includes a single NOx RACT analysis for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing (OCA) furnaces, and one (1) Continuous Anneal Furnace because these units have a similar design and function, combust the same fuels, and are expected to have similar emission profiles.

In general, annealing relieves cooling stresses induced by hot-or-cold working and softens the steel to improve its machinability or formability. This is accomplished by subjecting the steel to a controlled temperature profile or cycle with moderate peak temperatures. As compared with most iron and steel processes, which take place at temperatures of 2,000-3,000°F, annealing is accomplished at moderate temperatures usually below 1,000°F. Because of these lower temperatures, NOx emissions from these processes are lower.

**HPH Annealing Furnaces**
The HPH Annealing Process consists of 31 individual movable furnaces with 58 bases in one unit that treat coiled steel rolls. Each furnace is equipped with 12 burners, fired with coke oven gas enriched with natural gas, and has a maximum heat input rating of 4.9 MMBtu/Hr; emissions exhaust to stack SP10. Emissions are uncontrolled. The exhaust temperature of the furnace is 800°F.

It should be noted that the Title V operating permit, condition V.E.1.a, states that "The HPH Annealing Furnaces shall only combust coke oven gas and natural gas." [§2102.04.b.5].

It should also be noted that the Title V operating permit, condition V.E.1.e, states that emissions from HPH furnaces No. 1 through No. 31, shall not exceed the following [§2104.02.d.1, §2104.03.a.2.A and §2105.21.h.4]:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr (each unit)</th>
<th>tons/yr (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>0.49</td>
<td>0.74</td>
<td>3.22</td>
<td>99.82</td>
</tr>
</tbody>
</table>

Open Coil Annealing Furnaces

The OCA furnaces [P010] consists of 16 individual furnaces that heat treat open coiled steel rolls. Each furnace is fired with coke oven gas that is enriched with natural gas.

- Furnaces No. 1 through No. 9 have a total of 18 burners and have a maximum heat input rating of 7.2 MMBTU/Hr each;
- Furnaces No. 10 through No. 13 have a total of 18 burners and a maximum heat input rating of 9.0 MMBTUs/Hr, each;
- Furnace No. 14 has a total of 14 burners and a maximum heat input rating of 5.4 MMBtu/hr; and
- Furnaces No. 15 and 16 have a total of 18 burners and a maximum heat input rating of 7.47 MMBtu/hr.

All furnaces exhaust to stack SP12; emissions are uncontrolled. The exhaust temperature for the OCA furnaces is 800°F.

It should be noted that the Title V operating permit, condition V.F.1.a, states that "Only coke oven gas and natural gas shall be combusted in the No. 1 through No. 14 Open Coil Annealing Furnaces." [§2102.04.b.5 and §2102.04.b.6]. Additionally, Installation Permit #0050-I006, Condition V.A.1.a, states that "Only natural gas and coke oven gas shall be combusted in Open Coil Annealing (OCA) Furnaces No. 15 and 16." [§2102.04.b.6]

It should also be noted that the Title V operating permit, condition V.F.1.f, states that emissions from the open coil annealing furnaces shall not exceed the following [§2104.02.d.1, §2104.03.a.2.A and §2105.21.h.4]:

<table>
<thead>
<tr>
<th>NOx Limit</th>
<th>lb NOx/MBBtu</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr (each unit)</th>
<th>tons/yr (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. 1 through No. 9</td>
<td>0.40</td>
<td>0.72</td>
<td>2.88</td>
<td>12.61</td>
<td>113.49</td>
</tr>
<tr>
<td>No. 10 through No. 13</td>
<td>0.40</td>
<td>0.90</td>
<td>3.60</td>
<td>15.77</td>
<td>63.08</td>
</tr>
<tr>
<td>No. 14</td>
<td>0.29</td>
<td>0.75</td>
<td>1.20</td>
<td>5.20</td>
<td>--</td>
</tr>
</tbody>
</table>
Installation Permit #0050-I006, Condition V.A.1.c states “The permittee shall not operate, or allow to be operated OCA furnaces No. 15 and No. 16 unless the furnace is properly installed, operated and maintained according to good combustion and air pollution control practices, at all times.” [§2102.04.b.6]. Condition V.A.1.d states, “The permittee shall not operate, or allow to be operated OCA furnaces No. 15 and No. 16 unless the furnaces are equipped with low-NOX burners with maximum NOX emissions of 0.0375 lbs/MMBtu for natural gas combustion, corrected to 3 percent excess oxygen, and 0.0465 lbs/MMBtu for coke oven gas combustion, corrected to 3 percent excess oxygen.” [§2102.04.b.6]

Additionally, Installation Permit #0050-I006, Condition V.A.1.a, states that emissions from Open Coil Annealing Furnaces No. 15 and No. 16, shall not exceed the following [§2102.04.b.6, §2105.21.h.4]:

<table>
<thead>
<tr>
<th>NOx Limits</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr (each unit)</th>
<th>tons/yr (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. 15 and No. 16</td>
<td>0.28</td>
<td>0.35</td>
<td>1.52</td>
<td>3.04</td>
</tr>
</tbody>
</table>

Continuous Annealing Furnace

The one (1) Continuous Annealing Furnace [P011] consists of one furnace rated at 45 MMBtu/hr along with associated coiling, uncoiling and cleaning equipment. The furnace is equipped with 150 burners and fired with coke oven gas that is enriched with natural gas and is uncontrolled; emissions are routed to stack SP 13. The exhaust temperature for this furnace is 72°F.

It should be noted that the Title V operating permit, condition V.G.1.a, states that “Only coke oven gas and natural gas shall be combusted in the Continuous Annealing furnace.” [§2102.04.b.5]

It should also be noted that the Title V operating permit, condition V.G.1.g, states that NOx emissions from the Continuous Annealing Furnace shall not exceed 4.5 lbs/hr when combusting natural gas, 18.00 lb/hr when combusting coke oven gas, and total emissions shall not exceed 78.84 tons per year. [§2104.02.a.1, §2104.03.2.A, §2105.21.h.4].

Step 1 – Identify Control Options

ACHD reviewed U.S. Steel – Irvin's RACT submittal for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA’s Alternative Control Techniques (ACT) Document for Iron and Steel Mills16, and the study “Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis”17 to determine if any other controls have been demonstrated since 1994 when the ACT was published. The identified controls are discussed below:


The ACT identifies the following controls for annealing furnaces:

1. LNB
2. LNB + FGR
3. SCR

U.S. Steel Irvin also identified the following control measures in their RACT submittal:

4. FGR
5. Over-fire Air (OFA)
6. Selective Non-Catalytic Reduction (SNCR)
7. Regenerative Selective Catalytic Reduction (RSCR)
8. Combustion Optimization

No additional control measures were identified for annealing furnaces, except for combinations of controls listed above. These control measures have been organized into 5 groups: combustion optimization, staged combustion, additions to combustion air or fuel, low NOx burners, and post combustion controls.

**Combustion Optimization**

Furnace operation can be optimized to reduce NOx emissions by modifying furnace burner settings. For example, sources can specifically control the level of excess air to reduce NOx.

(a) **Combustion Optimization**

Combustion optimization involves an analysis to determine the combination of equipment settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the furnace. Combustion optimization includes conducting an evaluation of existing equipment, (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms and actuators to including oxygen probes, 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 furnace operation.

In boilers, performing combustion optimization can improve NOx emissions by 5 to 40 percent.\(^{18}\) The actual NOx emission rate achieved is dependent on the difference between the optimal settings and the furnace settings being used before optimization.

**Staged Combustion**

Staged combustion includes air staging to delay combustion and lower flame temperatures.

(b) **Over-fire Air**

As with reheat furnaces, OFA may be used in annealing furnaces. As noted previously, over-fire air is an alternate combustion design in which the burners are fired more fuel-rich than normal, and the additional air needed to complete combustion is admitted through overfire air ports or an idle top row of burners. This causes a staged combustion of the fuel: the air flow routed directly to the burners is reduced to promote fuel rich combustion in the primary (i.e. flame) combustion zone. The subsequent and secondary air flow - the overfire air - completes the combustion

---

process. This design reduces NOx by delaying the combustion process and lowering the flame temperature, which suppresses thermal NOx formation. Additionally, the relatively low O2 levels in the combustion zone inhibits fuel NOx formation.

OFA serves as both a "stand-alone" approach and one that is paired with other control options such as LNB. It can be used with nearly any fuel and most combustion systems. In emissions tests on utility boilers, OFA has achieved average NOx reductions of 24-59 percent with oil, coal, and natural gas firing compared with baseline levels.19

OFA is more easily implemented on large, utility scale boilers than on smaller units and furnaces. As furnace size decreases, furnace volume decreases more quickly than furnace wall area, which can create problems with residence times for fuel combustion. Also, space for additional ductwork, furnace penetrations, and fans may be a problem. These factors are potential impediments to implementing OFA techniques in smaller iron and steel process facility furnaces, especially on retrofit basis.

Additions to Combustion Air or Fuel

Furnace operation can be optimized to reduce NOx emissions by injecting flue gases or other materials into the combustion zone. This controls the formation of NOx by controlling the stoichiometric ratio of the chemicals that react to form NOx. The addition of flue gas dilutes the combustion zone and reduces the combustion temperature, which in turn reduces the formation of thermal NOx.

(c) Flue Gas Recirculation

Flue gas recirculation works similarly in annealing furnaces as it does in reheat furnaces. Flue gas recirculation involves the recirculation of a portion - typically 20-30% - of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. From a strictly technical standpoint, FGR is feasible as long as there is no minimum operational temperature/oxygen requirement for the fuel fired emission unit. FGR may also affect fan capacity, furnace pressure, burner pressure drop, and turndown stability.

NOx reductions vary considerably depending on the type of fuel. When operated without additional controls, the normal NOx control efficiency range for FGR used in a furnace is 30-50%. When used in conjunction with LNB, FGR is capable of reducing NOx emissions by 50-72%.20

Low NOx Burners

Low NOx burners work to reduce NOx emissions by controlling the stages of combustion, lowering combustion zone temperatures to reduce the production of NOx.

(d) Low NOx Burners

Low NOx Burners (LNB) may be applied in annealing furnaces the same way in which they may be applied in reheat furnaces. Low NOx burners involve a burner design in which the supplied fuel and air are staged across the burner which results in lower combustion temperatures and reduced NOx formation.

19 Id.
in fuel-lean and fuel-rich combustion zones at the burner. In the fuel-lean zones, the
combustion temperature is lowered, reducing the production of NOx emissions. Both
the temperature and oxygen concentrations are lowered in the fuel-rich zones.

The estimated NOx control efficiency for LN Bs in moderate temperature applications,
such as an annealing furnace, is 50%.21 However when coupled with FGR or SCR
these efficiencies increase 82 and 85%, respectively.22

Post Combustion Control

Post combustion control includes the addition of technologies that reduce NOx emissions (as
opposed to preventing NOx generation). Generally, these technologies include the addition
of a catalyst or reactant into the exhaust stream which chemically reduces the NOx, allowing
for removal from the gas stream.

(e) **Selective Catalytic Reduction**

Selective Catalytic Reduction (SCR) 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 with the following basic reaction pathways:

\[
4NH_3 + 4NO + O_2 > 4N_2 + 6H_2O
\]
\[
8NH_3 + 6NO_2 > 7N_2 + 12H_2O
\]

The normal NOx control efficiency range for SCR is 70-90%.23

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.
Optimum NOx reduction occurs at catalyst bed temperatures of 600–750 °F for
conventional (vanadium or titanium based catalysts), 470–510 °F for platinum
catalysts, and 600–1000 °F temperature range for a zeolite catalyst. Water vapor and
elemental nitrogen are released to the atmosphere as part of the exhaust stream.

SCR has been extensively and quite successfully used in a very cost effective
manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and
internal combustion diesel engines in the United States. There have been few uses
of SCR in the iron and steel industry. SCR has been used with annealing furnaces.
As indicated above, the optimum temperature for SCR depends on the catalyst. Thus
the exit gas temperatures from some of the processes at iron and steel plants may
either be too high or too low, requiring either reheat (if too low) or dilution/quenching
(if too high) in order to effectively use SCR.

(f) **Selective Non-Catalytic Reduction**

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21 Alternative Control Techniques Document – NOx Emissions from Iron and Steel Mills (EPA
453/R-94-065) (September 1994) Available at:
http://www.epa.gov/airquality/ozonepollution/SIPToolkit/ctq_act/199409_nox_epa453_r-94-

22 "Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit
Technology (BART) Engineering Analysis" (March 30, 2005). Available at:

23 *Id.*
Like SCR, SNCR operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy (1600-2100°F).

The normal NOx control efficiency range for SNCR is 40-70%. To date there are no known installations of SNCR at iron and steel plants.

(g) Regenerative Selective Catalytic Reduction (RSCR)

Regenerative Selective Catalytic Reduction (RSCR) is similar to SCR in that it operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. As noted above, SCR systems typically operate at approximately 600-750°F for the destruction of NOx. In some cases, a gas stream may be routed to particulate matter collection device or other control following exit of the furnace; in this case, the stream is significantly cooled, which may reduce the effectiveness of a catalyst. RSCR introduces a regenerative heater (similar to that used in a regenerative thermal oxidizer) prior to routing to an SCR. The temperature of the flue gas is temporarily elevated to improve catalyst performance, and the heat is recovered before sending the clean flue gas to the stack. These systems are primarily used for tail-end/low temperature applications where the flue gas is relatively cool, with low levels of particulates and acid gases. Such systems have been demonstrated to achieve a NOx reduction efficiency >80%, when applied to a cold gas (e.g., after boiler and scrubber/particulate removal equipment). It is currently applied in biomass plants for small boiler applications.

Step 2 – Eliminate Technically Infeasible Control Options

A number of the control options identified are not technically feasible for controlling NOx emissions from the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace. A review of available controls identified low NOx burners, selective catalytic reduction, and selective non-catalytic reduction as technically feasible controls. This section presents the rationale explaining why each control option is, or is not, technically feasible.

(a) Combustion Optimization

Combustion optimization and operating and maintenance (O&M) practices are applicable to all types of furnaces combusting all types of fuels. Such practices are generally used throughout the industry to increase energy efficiency and lower fuel costs, as well as pollutant emissions. Currently, U.S. Steel – Irvin Plant is required to operate and maintain the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace in accordance with good combustion and air pollution control practices, per RACT Order No. 258.

Additionally, U.S. Steel – Irvin Plant is currently required to conduct an annual tune-up for the Continuous Annealing Furnace, per RACT Order No. 258. The annual tune-up includes inspection, adjustment, cleaning, or necessary 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 inspection of the air-to-fuel ration control system and adjustments necessary to ensure proper calibration and operation. The thirty-one (31) HPH Annealing Furnaces and sixteen (16) open coil annealing furnaces are not currently required to perform a tune-up.

Although these requirements may not include all of the adjustments and optimizations that would be conducted during a full combustion optimization they would address several of the issues and make the emission reduction effectiveness of a full optimization even more uncertain. Therefore, combustion/performance optimization practices are considered technically feasible for these furnaces, but the additional emission reductions cannot be predicted and they would be expected to be relatively low since the source is already performing many of the optimization activities. Similarly, although it is considered technically feasible for an annual tune-up to be performed for the thirty-one (31) HPH Annealing Furnaces and sixteen (16) open coil annealing furnaces (as it is performed for similar sources), it is not clear what emission reductions would be achieved and it would not be known until the annual tune-up was completed. Because of these uncertainties, this control measure is considered technically infeasible.

(b) Over-fire Air

Over-fire air (OFA) is a combustion design in which a controlled portion of the combustion air flow is diverted to injection ports beyond the last row of burners. 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. Steel making equipment (i.e. reheat and annealing furnaces) are direct fired sources and not typically amenable to substantive excess oxygen control. Due to these issues, the use of over-fire air is not considered a technologically feasible option for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace.

(c) Flue Gas Recirculation

FGR involves the recirculation of a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. Although the ACT for Iron and Steel Mills considers the use of LNB plus FGR, the ACT provides that FGR has principally been applied to boilers and process heaters, and only includes data for use of LNB plus FGR controls for one annealing furnace.27

U.S. Steel – Irvin Plant provided that the oxygen content provided in each zone of the annealing furnaces can have a significant effect on product quality (due to changes in temperature at the flame tip/slab interface). Additionally, vendors for FGR were unable to provide specific estimates of potential NOx reductions without performing detailed studies on the specific furnaces, which use coke oven gas. Therefore, FGR is not considered a technologically feasible option for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace.

27 Id.
(d) **Low NOx Burners**

LNB technology is available from many manufacturers and applicable to all fuels, including coke oven gas. Low NOx burners (LNBs) have previously been installed in annealing furnaces, usually as part of a new furnace unit. Existing furnaces have also been retrofitted with LNBs. LNBs have been shown to be effective in reducing NOx emissions in annealing furnaces, both new and retrofitted. Therefore, LNBs are considered technically feasible for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace.

Although technically feasible, LNB technology would need to be carefully designed based on furnace sensitivities involving metallurgy and product quality. These components are highly affected by the burner flame length, temperature, and distribution (too much flame results in scaling, too little can produce stress issues in the finished product).

Preliminary vendor estimates provided for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace included:

- For a single HPH annealing furnace, the vendor provided a non-guaranteed estimate of NOx emissions of 0.11 lbs/MMBtu.
- A preliminary vendor estimate for a single OCA furnace provided a non-guaranteed estimate of NOx emissions of 0.12 lbs/MMBtu from OCA furnaces Nos. 1-9 and 0.10 lbs/MMBtu for furnaces Nos. 10-13. OCA furnaces No. 14, 15, and 16 currently utilize LNB technology.
- For the Continuous Annealing Furnace, the vendor provided preliminary predicted NOx emissions estimates at a 50% reduction from the existing burners, or 0.20 lb/MMBtu/hr.

(e) **Selective Catalytic Reduction**

There has been limited application of SCR units on furnaces that are similar in size to the annealing furnaces. Where it has been applied, SCR in annealing furnaces in the United States has resulted in a reduction of NOx emissions. However, the use of SCR in annealing furnaces has resulted in degrading of the SCR system very quickly (i.e., frequent catalyst damage), and ammonia slip has been a problem. Exhaust heat variations, flow rates, gas composition, and oxygen content all present issues in the operation of an SCR on an annealing furnace. With these considerations, SCR is considered to be technically feasible for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace.

(f) **Selective Non-Catalytic Reduction**

SNCR is similar to SCR, but it does not use a catalyst. SNCR has not been used on annealing furnaces in the United States. As with SCR, exhaust heat variations, flow rates, gas composition, and oxygen content are expected to present issues in the operation of an SNCR on a reheat furnace. For the HPH annealing furnaces and the OCA annealing furnaces, the exhaust temperature of each furnace is ~800°F. The exhaust temperature of the Continuous Annealing Furnace is 72°F. Therefore, significant auxiliary natural gas would be required to heat the furnace exhaust to a minimum SNCR temperature (~1600°F) for each furnace. With these considerations, SNCR is considered to be technically feasible for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace.
Regenerative Selective Catalytic Reduction (RSCR)

RSCR is similar to SCR but introduces a regenerative heater to elevate the temperature of flue gas to improve catalyst performance, and heat is recovered before sending the clean flue gas to the stack. RSCR has the ability to use the majority of heat which is lost to the stack, and therefore requires significantly less additional fuel use than other technologies. RSCR has not been used on slab furnaces such as annealing furnaces in the United States. Instead, this technology has largely been used at biomass plants in small boiler applications. Extensive research and pilot testing are needed to determine whether this technology is feasible for large coke oven gas fired furnaces. Additionally, extensive rerouting of ductwork would be required. For this reason, RSCR is not considered to be technically feasible for the thirty-one (31) HPH Annealing furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace at this time.

Step 3 - Evaluate Control Options

Emissions and Emission Reductions

The table below shows the NOx emissions from the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace, the technically feasible control options for these units, and the estimated control efficiency of each control option.

Table 5. Annealing Furnaces – NOx Control Options

<table>
<thead>
<tr>
<th>Unit(s)</th>
<th>Potential to Emit NOx (tpy, all units)</th>
<th>Control Type</th>
<th>Estimated NOx Control Efficiency (%)</th>
<th>Total Estimated NOx Emission Reductions (tpy, all units)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HPH Annealing Furnaces (31 units)</td>
<td>99.8(^a)</td>
<td>LNB</td>
<td>27(^c)</td>
<td>26.7</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCR</td>
<td>80(^d)</td>
<td>80.6</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45(^a)</td>
<td>43.4</td>
</tr>
<tr>
<td>OCA Furnaces 1-9 (9 units)</td>
<td>113.5(^a)</td>
<td>LNB</td>
<td>70(^f)</td>
<td>79.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCR</td>
<td>80(^d)</td>
<td>90.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45(^a)</td>
<td>51.3</td>
</tr>
<tr>
<td>OCA Furnaces 10-13 (4 units)</td>
<td>63.1(^a)</td>
<td>LNB</td>
<td>75(^e)</td>
<td>47.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCR</td>
<td>80(^d)</td>
<td>50.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45(^a)</td>
<td>28.4</td>
</tr>
<tr>
<td>OCA Furnace 14 (1 unit)</td>
<td>6.85(^b)</td>
<td>SCR</td>
<td>80(^d)</td>
<td>5.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45(^a)</td>
<td>3.1</td>
</tr>
<tr>
<td>OCA Furnaces 15-16 (2 units)</td>
<td>18.9(^b)</td>
<td>SCR</td>
<td>80(^d)</td>
<td>15.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45(^a)</td>
<td>8.6</td>
</tr>
<tr>
<td>Continuous Annealing Furnace (1 unit)</td>
<td>78.84(^a)</td>
<td>LNB</td>
<td>50(^h)</td>
<td>39.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCR</td>
<td>80(^d)</td>
<td>63.1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45(^a)</td>
<td>35.5</td>
</tr>
</tbody>
</table>

\(^a\) Based on potential to emit calculations from Title V Operating Permit #0050 (February 18, 2005) for COG.

\(^b\) Based on permitted NOx limit of 0.29 lb/MMBtu from Title V Operating Permit #0050 (February 18, 2005), for COG.

\(^c\) Derived from vendor quote of 0.11 lb/MMBtu.

\(^d\) Based on average NOx control efficiency from “Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis” (March 30, 2005).

\(^e\) Based on NOx control efficiency range from “Alternative Control Techniques Document – NOx Emissions from Iron and Steel Mills (EPA 453/R-94-065) (September 1994)”.

\(^f\) Derived from vendor quote of 0.12 lb/MMBtu.

\(^g\) Derived from vendor quote of 0.10 lb/MMBtu.
Economic Analysis

Using information provided by U.S. Steel – Irvin Plant and collected by ACHD, thorough economic analyses of the technically feasible control options for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing furnaces, and one (1) Continuous Anneal Furnace were conducted - see Appendix B for more information. The analyses estimate 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, except for direct installation costs, were calculated using the methodology described in Section 6, Chapter 1 of the “EPA Air Pollution Control Cost Manual, Sixth Edition” (document # EPA 452-02-001). Direct capital cost is based on a vendor quote. Annualized costs are based on an interest rate of 7% and an equipment life of 15 years for LNB and 20 years for SCR and SNCR.

The basis of cost effectiveness, used to evaluate the control option, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost figures for the individual furnaces is provided in the table below. Costs and NOx removal are based on a single representative furnace from each group.

<table>
<thead>
<tr>
<th>Table 5a. Annealing Furnaces – Economic Analysis for NOx Technically Feasible Control Options</th>
<th>Option</th>
<th>Total Capital Investment ($/furnace)</th>
<th>Total Annualized Cost ($/furnace/yr)</th>
<th>Potential NOx removal from control (ton/furnace/yr)</th>
<th>Cost Effectiveness ($/ton NOx removed/furnace)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HPH Annealing Furnaces</td>
<td>LNB</td>
<td>$532,271</td>
<td>$79,774</td>
<td>0.86</td>
<td>$92,925</td>
</tr>
<tr>
<td></td>
<td>SCR</td>
<td>$493,614</td>
<td>$121,061</td>
<td>2.6</td>
<td>$47,006</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$359,291</td>
<td>$522,439</td>
<td>1.4</td>
<td>$360,630</td>
</tr>
<tr>
<td>OCA Furnaces 1-9</td>
<td>LNB</td>
<td>$582,154</td>
<td>$86,748</td>
<td>8.8</td>
<td>$9,824</td>
</tr>
<tr>
<td></td>
<td>SCR</td>
<td>$703,841</td>
<td>$173,895</td>
<td>10.1</td>
<td>$17,232</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$425,076</td>
<td>$936,080</td>
<td>5.7</td>
<td>$164,905</td>
</tr>
<tr>
<td>OCA Furnaces 10-13</td>
<td>LNB</td>
<td>$727,693</td>
<td>$107,093</td>
<td>11.8</td>
<td>$9,056</td>
</tr>
<tr>
<td></td>
<td>SCR</td>
<td>$823,459</td>
<td>$199,421</td>
<td>12.6</td>
<td>$15,809</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$467,887</td>
<td>$1,115,375</td>
<td>7.1</td>
<td>$157,192</td>
</tr>
<tr>
<td>OCA Furnace 14a</td>
<td>SCR</td>
<td>$505,565</td>
<td>$126,669</td>
<td>5.5</td>
<td>$23,084</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$375,179</td>
<td>$459,978</td>
<td>3.1</td>
<td>$149,025</td>
</tr>
<tr>
<td>OCA</td>
<td>SCR</td>
<td>$741,091</td>
<td>$173,074</td>
<td>7.6</td>
<td>$22,801</td>
</tr>
</tbody>
</table>

h Based on NOx emission rates derived from Bloom Engineering quotation dated December 17, 2014.
### Furnaces 15-16

<table>
<thead>
<tr>
<th>Option</th>
<th>Total Capital Investment ($/furnace)</th>
<th>Total Annualized Cost ($/furnace/yr)</th>
<th>Potential NOx removal from control (ton/furnace/yr)</th>
<th>Cost Effectiveness ($/ton NOx removed/furnace)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SNCR</td>
<td>$431,113</td>
<td>$936,043</td>
<td>4.3</td>
<td>$219,225</td>
</tr>
<tr>
<td>Continuous Annealing Furnace</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNB</td>
<td>$5,265,953</td>
<td>$736,152</td>
<td>39.4</td>
<td>$18,675</td>
</tr>
<tr>
<td>SCR</td>
<td>$1,858,559</td>
<td>$1,704,813</td>
<td>63.1</td>
<td>$27,030</td>
</tr>
<tr>
<td>SNCR</td>
<td>$942,662</td>
<td>$3,874,267</td>
<td>35.5</td>
<td>$109,202</td>
</tr>
</tbody>
</table>

*OCA furnaces No. 14, 15, and 16 currently utilize LNB technology.*

Additionally, ACHD analyzed the total costs associated with the application of SCR to all annealing furnaces (HPH, OCA, and CAF) combined. These costs were included because it is assumed that the facility could feasibly install a single SCR to control the combined exhausts of each annealing furnace, reducing NOx emissions by 291 tons per year, with a greater cost-effectiveness than installing SCR on each single furnace. SCR was chosen because auxiliary costs to heat the exhaust for an SNCR would likely continue to be costly. The table below shows the estimated costs of such an SCR system.

### Table 5b. Annealing Furnaces – Economic Analysis for Single SCR for NOx Control

<table>
<thead>
<tr>
<th>Unit(s)</th>
<th>Option</th>
<th>Total Capital Investment ($/furnace)</th>
<th>Total Annualized Cost ($/furnace/yr)</th>
<th>Potential NOx removal from control (ton/furnace/yr)</th>
<th>Cost Effectiveness ($/ton NOx removed/furnace)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HPH Annealing Furnaces; OCA Furnaces; and Continuous Annealing Furnace</td>
<td>SCR</td>
<td>$8,231,450</td>
<td>$1,451,970</td>
<td>291</td>
<td>$4,993</td>
</tr>
</tbody>
</table>

### Step 4 – Select RACT

LNB and SNCR are not considered cost effective. The low NOx burners have relatively low annualized costs; however, the emission reductions are low, for each individual furnace which makes the cost effectiveness value high. It is also not surprising that the SNCR is not cost effective given the additional natural gas that must be burned to get the exhaust temperatures high enough to use these controls. For the HPH annealing furnaces and the OCA annealing furnaces, the exhaust temperature of each furnace is ~800°F. The exhaust temperature of the Continuous Annealing Furnace is 72°F. Therefore, significant auxiliary natural gas would be required to heat the exhaust from each furnace to a minimum SNCR temperature (~1600°F). Burning the additional natural gas not only adds cost to the use of this technology, but additional NOx and other pollutants will be emitted to heat the exhaust to the appropriate levels.

Based on the costs shown in Table 5b, installing a single SCR unit for the HPH Annealing Furnaces, Open Coil Annealing Furnaces, and Continuous Annealing Furnace would be a cost effective NOx control option. The emission rate for the exhaust stream of the combined controlled units would be 0.052 lb/MMBtu.
ACHD considers the application of a single SCR unit with an emission rate of 0.052 lb/MMBtu to be considered RACT for the thirty-one (31) HPH Annealing Furnaces, sixteen (16) open coil annealing (OCA) furnaces, and one (1) Continuous Anneal Furnace.

C. RACT for NOx – No.1 Continuous Galvanizing Line preheat furnaces, No.1 Continuous Galvanizing Line galvanneal furnace, and No.2 Continuous Galvanizing & Aluminum Coating Lines, preheat furnace

This section includes a single NOx RACT analysis for:

1. No.1 Continuous Galvanizing Line natural gas-fired melt pot preheat furnace rated at 50 MMBtu/hr, exhausting to stack SP15. The No. 1 melt pot pre-heat furnace is used to melt the coating materials prior to galvanizing. The melt pot furnace is of vertical movement design and provides a direct flame impingement on the strip from 240 burners throughout the furnace. Burners are installed within and through the furnace wall firebrick. On the reduction side of the furnace the system is operated fuel rich with cold air. Exhaust gases are emitted at a temperature of 840-1000°F.

2. No.1 Continuous Galvanizing Line natural gas-fired galvanneal furnace rated at 18 MMBtu/hr, exhausting to stack SP16. The No. 1 Continuous Galvanizing Line preheat furnace is equipped with 24 burners and has an exhaust flow rate of 1,240°F.

3. No.2 Continuous Galvanizing & Aluminum Coating Lines preheat furnace. The No. 2 Continuous Galvanizing & Aluminum Coating Process consists of one preheat furnace rated at 18 MMBtu/hr along with associated cleaning, treating and galvalume equipment. The unit is used to melt the coating materials prior to galvanizing. Emissions from the furnace are uncontrolled and exhaust to stack SP18. The unit is equipped with 18 burners and has an exhaust flow temperature of 1,240°F.

These units are addressed in one RACT analysis because they have a similar design and function, combust natural gas, and are expected to have similar emission profiles. In galvanizing, steel products are coated with a protective layer of zinc, aluminum, terne, or a zinc-aluminum alloy (galvalume) to provide protection against corrosion. The furnaces provide heat for the molten bath of zinc or galvalume. Typical temperatures for galvanizing furnaces are around 840°F.

The Title V operating permit, condition V.H.1.a, states that "Only natural gas shall be combusted in the No. 1 Continuous Galvanizing Line preheat and galvanneal furnaces." [§2102.04.b.5] A permit should be issued in the summer of 2015 that will allow these furnaces to also burn COG.

The Title V operating permit, condition V.H.1.c, states that emissions from preheat furnace and the galvanneal furnace shall not exceed the following [§2104.02.a.1.A and §2104.03.a.1]:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Preheat Furnace</th>
<th>Galvanneal Furnace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lbs/hr</td>
<td>tons/yr</td>
</tr>
<tr>
<td>NOx</td>
<td>3.0</td>
<td>13.14</td>
</tr>
</tbody>
</table>

The Title V operating permit, condition V.I.1.a, states that "only natural gas shall be combusted in the No. 2 Continuous Galvanizing and Aluminum Coating Line preheat furnace." [§2102.04.b.5]. A permit should be issued in the summer of 2015 that will allow these furnaces to also burn COG.
Additionally, Title V operating permit condition V.I.1.d states that NOx emissions from the preheat furnace shall not exceed 7.20 lbs per hour and 31.54 tons per year. [§2104.02.d.1, §2104.02.a.1.A and §2104.03.a.1]

Step 1 – Identify Control Options

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the No.1 Continuous Galvanizing Line preheat furnace [P012], No.1 Continuous Galvanizing Line (CGL) galvanneal furnace [P012], and No.2 Continuous Galvanizing & Aluminum Coating Lines (CGL) preheat furnace and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA’s Alternative Control Techniques (ACT) Document for Iron and Steel Mills28 and the study “Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis”29 to determine if any other controls have been demonstrated since 1994 when the ACT was published. The identified controls are discussed below:

The ACT identifies the following controls for galvanizing furnaces:

1. LNB
2. LNB + FGR

U.S. Steel Irvin also identified the following control measures in their RACT submittal:

3. FGR
4. Over-fire Air (OFA)
5. SCR
6. Selective Non-Catalytic Reduction (SNCR)
7. Regenerative Selective Catalytic Reduction (RSCR)

No additional control measures were identified for the galvanizing furnaces, except for combinations of controls listed above. These control measures have been organized into 5 groups: combustion optimization, staged combustion, additions to combustion air or fuel, low NOx burners, and post combustion controls.

Combustion Optimization

Furnace operation can be optimized to reduce NOx emissions by modifying furnace burner settings. For example, sources can specifically control the level of excess air to reduce NOx.

(a) Combustion Optimization

Combustion optimization involves an analysis to determine the combination of equipment settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the furnace. Combustion optimization includes conducting an evaluation of existing equipment, (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms and actuators to including oxygen probes, 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 furnace operation. In boilers, performing combustion optimization can improve NOx emissions by 5 to 40 percent. The actual NOx emission rate achieved is dependent on the difference between the optimal settings and the furnace settings being used before optimization.

**Staged Combustion**

Staged combustion includes air staging to delay combustion and lower flame temperatures.

**(b) Over-fire Air**

As with reheat and annealing furnaces, OFA may be used in galvanizing furnaces. As noted previously, over-fire air is an alternate combustion design in which the burners are fired more fuel-rich than normal, and the additional air needed to complete combustion is admitted through overfire air ports or an idle top row of burners. This causes a staged combustion of the fuel: the air flow routed directly to the burners is reduced to promote fuel rich combustion in the primary (i.e. flame) combustion zone. The subsequent and secondary air flow - the overfire air - completes the combustion process. This design reduces NOx by delaying the combustion process and lowering the flame temperature, which suppresses thermal NOx formation. Additionally, the relatively low O2 levels in the combustion zone inhibits fuel NOx formation.

In utility boilers, OFA has achieved average NOx reductions of 24 to 59% with oil, coal, and natural gas.

As noted previously, OFA is less easily implemented on smaller units and furnaces. As furnace size decreases, furnace volume decreases more quickly than furnace wall area, which can create problems with residence times for fuel combustion. Also, space for additional ductwork, furnace penetrations, and fans may be a problem. These factors are potential impediments to implementing OFA techniques in smaller iron and steel process facility furnaces, especially on retrofit basis.

**Additions to Combustion Air or Fuel**

Furnace operation can be optimized to reduce NOx emissions by injecting flue gases or other materials into the combustion zone. This controls the formation of NOx by controlling the stoichiometric ratio of the chemicals that react to form NOx. The addition of flue gas dilutes the combustion zone and reduces the combustion temperature, which in turn reduces the formation of thermal NOx.

**(c) Flue Gas Recirculation**

Flue gas recirculation works similarly in annealing furnaces as it does in reheat furnaces. Flue gas recirculation involves the recirculation of a portion - typically 20-30% - of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. From a strictly technical

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standpoint, FGR is feasible as long as there is no minimum operational temperature/oxygen requirement for the fuel fired emission unit. FGR may also affect fan capacity, furnace pressure, burner pressure drop, and turndown stability.

NOx reductions vary considerably depending on the type of fuel. When operated without additional controls, the normal NOx control efficiency range for FGR used in a furnace is 30-50%. When used in conjunction with LNB, FGR is capable of reducing NOx emissions by 50-72%.\(^\text{32}\)

**Low NOx Burners**

Low NOx burners work to reduce NOx emissions by controlling the stages of combustion, lowering combustion zone temperatures to reduce the production of NOx.

\((d)\) **Low NOx Burners**

Low NOx Burners (LNB) may be applied in galvanizing furnaces the same way in which they may be applied in reheat furnaces. Low NOx burners involve a burner design in which the supplied fuel and air are staged across the burner which results in fuel-lean and fuel-rich combustion zones at the burner. In the fuel-lean zones, the combustion temperature is lowered, reducing the production of NOx emissions. Both the temperature and oxygen concentrations are lowered in the fuel-rich zones.

The assumed NOx control efficiency for LNBs in a galvanizing furnace is 50%.\(^\text{33}\) However when coupled with FGR or SCR, this efficiency increases from 50-72%, respectively.\(^\text{34}\)

**Post Combustion Control**

Post combustion control includes the addition of technologies that reduce NOx emissions (as opposed to preventing NOx generation). Generally, these technologies include the addition of a catalyst or reactant into the exhaust stream which chemically reduces the NOx, allowing for removal from the gas stream.

\((e)\) **Selective Catalytic Reduction**

Selective Catalytic Reduction (SCR) 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 with the following basic reaction pathways:

\[
4\text{NH}_3 + 4\text{NO} + \text{O}_2 > 4\text{N}_2 + 6\text{H}_2\text{O} \\
8\text{NH}_3 + 6\text{NO}_2 > 7\text{N}_2 + 12\text{H}_2\text{O}
\]


The normal NOx control efficiency range for SCR is 70-90%.\(^{35}\)

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. Optimum NOx reduction occurs at catalyst bed temperatures of 600–750 °F for conventional (vanadium or titanium based catalysts), 470–510 °F for platinum catalysts, and 600–1000 °F temperature range for a zeolite catalyst. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the United States. SCR is not typically used with galvanizing furnaces.

(f) Selective Non-Catalytic Reduction

Like SCR, SNCR operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy (1600-2100°F).

The normal NOx control efficiency range for SNCR is 40-70%.\(^{36}\) To date there are no known installations of SNCR at iron and steel plants.\(^{37}\)

(g) Regenerative Selective Catalytic Reduction (RSCR)

Regenerative Selective Catalytic Reduction (RSCR) is similar to SCR in that it operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. As noted above, SCR systems typically operate at approximately 600-750°F for the destruction of NOx. In some cases, a gas stream may be routed to particulate matter collection device or other control following exit of the furnace; in this case, the stream is significantly cooled, which may reduce the effectiveness of a catalyst. RSCR introduces a regenerative heater (similar to that used in a regenerative thermal oxidizer) prior to routing to an SCR. The temperature of the flue gas is temporarily elevated to improve catalyst performance, and the heat is recovered before sending the clean flue gas to the stack. These systems are primarily used for tail-end/low temperature applications where the flue gas is relatively cool, with low levels of particulates and acid gases. Such systems have been demonstrated to achieve a NOx reduction efficiency >80%, when applied to a cold gas (e.g., after boiler and scrubber/particulate removal equipment). It is currently applied in biomass plants for small boiler applications.

Step 2 – Eliminate Technically Infeasible Control Options

A number of the control options identified are not technically feasible for controlling NOx at the No.1 CGL preheat furnace [P012], No.1 CGL galvanneal furnace [P012], and the No.2

\(^{35}\) Id.


CGL preheat furnace. A review of available controls identified selective catalytic reduction and selective non-catalytic reduction as technically feasible controls. This section presents the rationale explaining why each control option is, or is not, technically feasible for each emission unit.

(a) **Combustion Optimization**

Combustion optimization and operating and maintenance (O&M) practices are applicable to all types of furnaces combusting all types of fuels. Such practices are generally used throughout the industry to increase energy efficiency and lower fuel costs, as well as pollutant emissions. Currently, U.S. Steel – Irvin Plant is required to operate and maintain the No.1 CGL preheat furnace [P012], No.1 CGL galvanneal furnace [P012], and the No.2 CGL preheat furnace, in accordance with the good combustion and air pollution control practices, per RACT Order No. 258. Therefore, combustion/performance optimization practices are considered technically feasible for these sources, but no additional emission reductions would result because the source is already performing this activity.

The No.1 CGL preheat furnace [P012], No.1 CGL galvanneal furnace [P012], and the No.2 CGL preheat furnace, are not currently required to perform a tune-up. Although it is considered technically feasible for an annual tune-up to be performed for these sources as it is performed for similar sources, it is not clear what emission reductions would be achieved and it would not be known until the annual tune-up was completed. Because of this uncertainty, this control measure is considered technically infeasible.

(b) **Over-fire Air**

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. Steel making equipment (i.e. galvanizing furnaces) are direct fired sources and not typically amenable to substantive excess oxygen control. Due to these issues, the use of OFA is not considered a technologically feasible option for the No.1 CGL preheat furnace, No.1 CGL galvanneal furnace, and the No.2 CGL preheat furnace.

(c) **Flue Gas Recirculation**

FGR involves the recirculation of a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. 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. Steel making equipment (i.e. galvanizing furnaces) are direct fired sources and not typically amenable to substantive excess oxygen control. Furthermore, although the ACT for Iron and Steel Mills considers the use of FGR in combination with low NOx burners, the ACT provides that FGR has principally been applied to boilers and process heaters, and only reports use of LNB plus FGR controls for two galvanizing furnaces.38

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Due to these issues, the use of FGR is not considered a technologically feasible option for the No.1 CGL preheat furnace, No.1 CGL galvanneal furnace, and the No.2 CGL preheat furnace.

(d) **Low NOx Burners**

Low NOx Burner (LNB) technology is available from many manufacturers and applicable to all fuels. LNBs have previously been installed in similar furnaces. LNBs have been shown to be effective in reducing NOx emissions in similar types of furnaces.

For the No. 1 CGL preheat furnace, the furnace has a maximum heat input of 50 MMBtu/hr, is of a vertical movement design, and provides direct flame impingement on the strips from 240 burners throughout the furnace. Burners are installed within and throughout the furnace wall firebrick. On the reduction side of the furnace, the system is operated with fuel-rich cold air. The No. 1 CGL Galvanneal Furnace has a rated heat input capacity of 18 MMBtu/hr and is equipped with 24 burners.

Although LNB could technically be used for both the No. 1 CGL preheat furnace and the No. 1 CGL Galvanneal furnace, each burner would need to be replaced with a burner of similar size and design (i.e., flame speed, temperature length, heat output). Vendors were not aware of replacement burners matching the current specifications that operate in the low NOx mode, and indicated that they could not provide equivalent burners that would allow the No 1 CGL preheat furnace and No. 1 CGL Galvanneal furnace to run properly. Replacement of the existing burners with non-equivalent burners could have implications for burner flame length, temperature, and distribution, which could result in implications for product quality. Additionally, although the ACT for Iron and Steel Mills considers the use of LNB for galvanneal furnaces, the ACT only reports use of LNB for one galvanizing furnace with a limited NOx emissions reduction efficiency of 34%. With these considerations, LNB is not considered feasible for the No. 1 CGL preheat furnace or the No 1 CGL Galvanneal furnace.

The No. 2 CGL preheat furnace, which has a rated heat capacity of 18 MMBtu, is equipped with 18 burners. The current burner vendor, Bloom Engineering, reviewed the data and specifications for the current burners and concluded that the current burner arrangement is the lowest NOx that could be achieved using Bloom burners (i.e., the No. 2 CGL preheat furnace is currently operating with Bloom LNBs). Therefore, LNBs were not further considered for the No. 2 CGL preheat furnace.

(e) **Selective Catalytic Reduction**

SCR units have been used on furnaces that are similar to the preheat and galvanneal furnaces in similar facilities in the United States. However, there has been limited application of SCR units on furnaces that are similar in size. Where it has been applied, SCR in galvanizing furnaces in the United States has resulted in a reduction of NOx emissions. However, the use of SCR in galvanizing furnaces has resulted in degrading of the SCR system very quickly (i.e., frequent catalyst damage), and ammonia slip has been a problem. Exhaust heat variations, flow rates, gas composition, and oxygen content all present issues in the operation of an SCR on a galvanizing furnace.

With these considerations, SCR is considered to be technically feasible for the No.1 Continuous Galvanizing Line preheat furnace [P012], No.1 Continuous Galvanizing

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39 [Id.]
Line galvanneal furnace [P012], and the No.2 Continuous Galvanizing & Aluminum Coating Lines preheat furnace. A cost analysis for these control options is presented in Step 3 – Evaluate Control Options below.

(f) **Selective Non-Catalytic Reduction**

SNCR is similar to SCR, but it does not use a catalyst. SCR units have been used on furnaces that are similar to the preheat and galvanneal furnaces in similar facilities in the United States. For this reason, SNCR is considered to be technically feasible for the No.1 Continuous Galvanizing Line preheat furnace [P012], No.1 Continuous Galvanizing Line galvanneal furnace [P012], and the No.2 Continuous Galvanizing & Aluminum Coating Lines preheat furnace. The exhaust temperature of the No. 1 CGL preheat furnace is between 840-1000°F. The exhaust temperatures of the No. 1 CGL galvanneal furnace and the No. 2 CGL preheat furnace are approximately 1240°F. Therefore, auxiliary natural gas could be required to heat the furnace exhaust to a minimum SNCR temperature (~1600°F) for each furnace.

(g) **Regenerative Selective Catalytic Reduction (RSCR)**

RSCR is similar to SCR but introduces a regenerative heater to elevate the temperature of flue gas to improve catalyst performance, and heat is recovered before sending the clean flue gas to the stack. RSCR has the ability to use the majority of heat which is lost to the stack, and therefore requires significantly less additional fuel use than other technologies. RSCR has not been used on steelmaking furnaces such as preheat or galvanneal furnaces in the United States. Instead, this technology has largely been used at biomass plants in small boiler applications. Extensive research and pilot testing are needed to determine whether this technology is feasible for coke oven gas fired furnaces. Additionally, extensive rerouting of ductwork would be required. For this reason, RSCR is not considered to be technically feasible for the No.1 Continuous Galvanizing Line preheat furnace [P012], No.1 Continuous Galvanizing Line galvanneal furnace [P012], and the No.2 Continuous Galvanizing & Aluminum Coating Lines preheat furnace at this time.

**Step 3 - Evaluate Control Options**

**Emissions and Emission Reductions**

The table below shows the emissions from the No.1 CGL preheat furnace [P012], No.1 CGL Galvanneal furnace [P012], and the No.2 CGL preheat furnace, the technically feasible control options for these units, and the estimated control efficiency of each control option.

**Table 6. Galvanizing Furnaces – NOx Control Options**

<table>
<thead>
<tr>
<th>Unit(s)</th>
<th>Potential to Emit (tpy)</th>
<th>Control Type</th>
<th>Estimated NOx Control Efficiency (%)</th>
<th>Estimated NOx Emission Reductions (tpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. 1 CGL preheat furnace</td>
<td>13.1&lt;sup&gt;a&lt;/sup&gt;</td>
<td>SCR</td>
<td>80&lt;sup&gt;b&lt;/sup&gt;</td>
<td>10.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45&lt;sup&gt;c&lt;/sup&gt;</td>
<td>5.9</td>
</tr>
<tr>
<td>No. 1 CGL Galvanneal furnace</td>
<td>7.88&lt;sup&gt;a&lt;/sup&gt;</td>
<td>SCR</td>
<td>80&lt;sup&gt;b&lt;/sup&gt;</td>
<td>6.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45&lt;sup&gt;c&lt;/sup&gt;</td>
<td>3.5</td>
</tr>
<tr>
<td>No. 2 CGL preheat furnace</td>
<td>31.5&lt;sup&gt;a&lt;/sup&gt;</td>
<td>SCR</td>
<td>80&lt;sup&gt;b&lt;/sup&gt;</td>
<td>25.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45&lt;sup&gt;c&lt;/sup&gt;</td>
<td>14.2</td>
</tr>
</tbody>
</table>

<sup>a</sup> Based on potential to emit calculations from Title V Operating Permit #0050 (February 18, 2005).

<sup>b</sup> Based on average NOx control efficiency from “Midwest Regional Planning Organization Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis” (March 30, 2005).
Economic Analysis

Using information provided by U.S. Steel – Irvin Plant and collected by ACHD, thorough economic analyses of the technically feasible control options for the No.1 CGL preheat furnace [P012], No.1 CGL Galvanneal furnace [P012], and the No.2 CGL preheat furnace were conducted - see Appendix C for more information. The analysis estimates 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, except for direct installation costs, were calculated using the methodology described in Section 6, Chapter 1 of the “EPA Air Pollution Control Cost Manual, Sixth Edition” (document # EPA 452-02-001). Direct capital cost is based on a vendor quote. Annualized costs are based on an interest rate of 7% and an equipment life of 20 years.

The basis of cost effectiveness, used to evaluate the control option, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost figures determined in the analysis is provided in the table below:

Table 7. Galvanizing Furnaces – Economic Analysis for Technically Feasible NOx Control Options

<table>
<thead>
<tr>
<th>Unit(s)</th>
<th>Option</th>
<th>Total Capital Investment ($)</th>
<th>Total Annualized Cost ($/yr)</th>
<th>Potential NOx removal from control (ton/yr)</th>
<th>Cost Effectiveness ($/ton NOx removed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. 1 CGL preheat furnace</td>
<td>SCR</td>
<td>$1,895,516</td>
<td>$300,088</td>
<td>10.5</td>
<td>$28,457</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$972,312</td>
<td>$1,510,535</td>
<td>5.9</td>
<td>$255,460</td>
</tr>
<tr>
<td>No. 1 CGL Galvanneal furnace</td>
<td>SCR</td>
<td>$1,223,845</td>
<td>$259,375</td>
<td>6.3</td>
<td>$41,124</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$626,447</td>
<td>$598,196</td>
<td>3.5</td>
<td>$168,611</td>
</tr>
<tr>
<td>No. 2 CGL preheat furnace</td>
<td>SCR</td>
<td>$997,912</td>
<td>$192,321</td>
<td>25.2</td>
<td>$7,623</td>
</tr>
<tr>
<td></td>
<td>SNCR</td>
<td>$631,308</td>
<td>$248,381</td>
<td>14.2</td>
<td>$17,502</td>
</tr>
</tbody>
</table>

Step 4 – Select RACT

None of the control options are considered cost effective. It is not surprising that the SNCR and SCR are not cost effective given the additional natural gas that must be burned to get the exhaust temperature high enough to use these controls. Burning the additional natural gas not only adds cost to the use of these technologies, but additional NOx and other pollutants will be emitted to heat the exhaust to the appropriate levels.

The No.1 CGL preheat furnace [P012], No.1 CGL galvanneal furnace [P012], and the No.2 CGL preheat furnace are already subject to the good combustion requirements of Article XXI; therefore, it was determined that RACT for these furnaces is no additional control, the existing limits on NOx emissions, and compliance with Article XXI.
Peachtree Flare

Four (4) open candle stick flares used for combusting excess COG with a maximum design rate of 6.75 MMCF/day each. Flaring generally only occurs when a major operation or source (such as a blast furnace or the Hot Strip Mill) is not in service. Although the flares are open flares, Flares No. 1 through No. 3 are designated as exhausting to the same stack, SP20; the Peachtree Flare exhausts to stack SP21.

It should be noted that the Title V operating permit, condition V.K.1.d, states that NOx emissions from each subject flare shall not exceed 9.56 lbs per hour and 41.88 tons per year. [§2101.02.c.4 and §2105.21.h.4]

Step 1 – Identify Control Options

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the three (3) coke oven gas flares and the Peachtree Flare 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, and a review EPA’s Standards of Performance for Petroleum Refineries to determine the available controls for flares.

Add-on controls are not available for flares because the flame is not enclosed, and thus the exhaust cannot be captured. EPA performed flare studies as part of development of the new source performance standards for refineries (40 CFR 60, Subpart J) in 2012. Based on 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 (to reduce smoking/opacity) and on minimization of fuel burned.

The identified 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 (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

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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.

FMP generally include 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.

FMPs do not result in specific NOx emissions reductions from a flare, but instead reduce the flow to the flare that generates NOx. However, because the NOx reductions depend on the source's ability to minimize the use of the flare, the emissions reductions cannot be predicted.

**Step 2 – Eliminate Technically Infeasible Control Options**

A number of the control options identified are not technically feasible for controlling NOx emissions from the three (3) coke oven gas flares and the Peachtree flare. This section presents the rationale explaining why each control option is, or is not, technically feasible.

(a) **Good engineering practices**

Good engineering practices include the operation and maintenance of the flares in accordance with the flare design, including any manufacturer's specifications and best practices. Such practices are recommended for optimal performance and are generally used throughout the industry. It is unclear how much operating using good engineering practices effects emissions from open flares. Therefore, this control measure is not evaluated further.

(b) **Flare minimization plan**

A flare minimization plan includes assessment and planning to reduce flare emissions by reducing the frequency and magnitude of flaring events. Flare management plans have been required of flares used at petroleum refineries, sulfur recovery plants, and hydrogen production plants, however, such plans could reasonably apply to the flares at the U.S. Steel – Irvin Plant.

The COG used at the facility is a byproduct obtained from coke ovens at U.S. Steel - Clairton Works and used downstream at the U.S. Steel – Edgar Thompson and U.S. Steel – Irvin Plant operations. The COG used at U.S. Steel – Irvin Plant must ultimately be flared for safety and to eliminate the small amount of hazardous air pollutants in the COG. U.S. Steel previously developed a system to reduce the amount of COG flared by converting the blast furnaces for all of its Mon Valley Works operations (Clairton Works, Edgar Thompson, and Irvin) to utilize COG. The current system includes a COG processing facility at U.S. Steel – Clairton Works which processes the COG until its content is approximately 50-60 percent hydrogen. The COG is partially supplemented with natural gas to enrich certain properties that are needed to operate the various furnaces. The COG/natural gas mixture is subsequently piped to the U.S. Steel – Edgar Thomson and U.S. Steel – Irvin
Plant operations, where it is used in reheat/annealing furnaces, and in collocated facilities.

The system devised by U.S. Steel Mon Valley Works displaces some of the natural gas previously used in the reheat/annealing furnaces at the Edgar Thompson and Irvin operations, and utilizes the COG produced at Clairton Works which would otherwise be flared. This system has resulted in significant reductions of the COG flared. When major manufacturing operations are normal, COG is completely utilized by the U.S. Steel Mon Valley Works operations. The flaring of COG is currently minimized to mainly times when a major operation or source are inactive. During scheduled maintenance outages, COG use is maximized at the other Mon Valley facilities.

Therefore, although a flare management plan is considered technically feasible for the three (3) coke oven gas flares and the Peachtree flare, U.S. Steel has previously evaluated and minimized the use of the flares. The system devised by U.S. Steel Mon Valley Works has also resulted in significant cost savings for the source. Therefore, the use of a flare minimization plan was not further considered for this source.

Step 3 - Evaluate Control Options

Emissions and Emission Reductions

The three (3) coke oven gas flares and the Peachtree flare have a potential to emit 41.8 tpy NOx each (or 167.5 tpy NOx for all flares) based on potential to emit calculations from the Title V Operating Permit #0050. The flares have a total design capacity of 27 million cubic feet per day or 6.75 mmcf/day per flare.

Step 4 – Select RACT

No additional controls are identified for the four coke oven gas flares. As discussed in Step 3, U.S. Steel – Irvin Plant has evaluated and minimized the use of flaring at the facility. The system devised by U.S. Steel Mon Valley Works displaces some of the natural gas previously used in the reheat/annealing furnaces, and utilizes COG which would otherwise be flared. This system has resulted in significant reductions of the COG flared and limits flaring to mainly times when a major operation or source are inactive.

E. RACT for NOx – Four (4) natural gas and coke oven fired boilers [B001, B002, B003, B004]

This section includes a single NOx RACT analysis for the four (4) natural gas and coke oven fired boilers [B001, B002, B003, B004] because these units have a similar design and function, combust the same fuels, and are expected to have similar emission profiles.

Boilers No. 1 through 4 are all package watertube boilers of a single-burner design that were constructed in 1987. Steam output from these boilers varies with facility demands and load rates can swing from 10:1 rather quickly. Boilers No. 1 through 4 are each currently controlled with low excess air (LEA) in the exhaust stream (less than 5%).

Boiler No. 1 [B001] is a natural gas and coke oven gas fired Nebraska Model UK Watertube boiler with a maximum heat input capacity of 79.8 MMBtu/hr. Boiler emissions exhaust to stack SB1.
Boiler No. 2 [B002] is a natural gas and coke oven gas fired Cleaver Brooks Model CL-76 watertube boiler with a maximum heat input capacity of 84.6 MMBtu/hr. Boiler emissions are exhaust to stack SB2.

Boilers No. 3 and No. 4 [B003 and B004] are natural gas and coke oven gas fired Nebraska Model UK watertube boilers each equipped with one burner and with a maximum heat input capacity of 41.6 MMBtu/hr each. Boiler emissions exhaust to stack SB3 and SB4, respectively. The exhaust flow and temperature for a single boiler have been estimated at 50,154 acfm and 700°F, respectively.

These boilers are permitted to burn only coke oven gas and natural gas. The Title V operating permit also limits NOx emissions to the following:

<table>
<thead>
<tr>
<th>Boiler</th>
<th>lb NOx/hr (natural gas)</th>
<th>lb NOx/hr (coke oven gas)</th>
<th>tons NOx/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>B001</td>
<td>7.98</td>
<td>12.77</td>
<td>55.92</td>
</tr>
<tr>
<td>B002</td>
<td>8.46</td>
<td>13.54</td>
<td>59.29</td>
</tr>
<tr>
<td>B003 &amp; B004 (each)</td>
<td>4.16</td>
<td>6.66</td>
<td>29.15</td>
</tr>
</tbody>
</table>

**Step 1 – Identify Control Options**

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the four (4) natural gas and coke oven fired boilers and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA’s Alternative Control Techniques (ACT) document for Industrial/Commercial/Institutional (ICI) Boilers\(^42\) and the “Assessment of Control Technology Options for BART-Eligible Sources“\(^43\) and investigated additional resources to determine if any other ICI boiler controls have been demonstrated since 1994 when the ACT was published. The identified controls are discussed below.

The ACT identifies the following controls for gas fired ICI boilers:

1. Low excess air (LEA)
2. Water or steam injection
3. Staged combustion
4. Fuel reburning
5. Low NOx burning
6. Flue gas recirculation (FGR)
7. Fuel induced recirculation (FIR)
8. Selective noncatalytic reduction (SNCR)
9. Selective catalytic reduction (SCR)
10. Fuel switching

U.S. Steel Irvin also identified the following control measures in their RACT submittal:

11. Regenerative Selective Catalytic Reduction (RSCR)

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No additional control measure was identified for ICI boilers, except for combinations of controls listed above. These control measures have been organized into 6 groups: combustion optimization, staged combustion, additions to combustion air or fuel, low NOx burners, post combustion controls, and fuel switching.

**Combustion Optimization**

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 level of excess air to reduce NOx.

(a) **Combustion Optimization**

Combustion optimization involves an analysis to determine the combination of equipment settings that result in optimal combustion with respect to NOx and CO emissions, opacity, efficiency, and sustainable operation of the furnace. Combustion optimization includes conducting an evaluation of existing equipment, (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms and actuators to including oxygen probes, 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 furnace operation.

Because of the large number of control parameters, computer software is usually used to analyze the boiler data collected and aid in determining the optimal settings. Computer programs can also be used to operate the boiler, to make small adjustments to the boiler control parameters in real time to respond to changing factors (e.g. fuel characteristics, fuel flow, temperature).

Performing combustion optimization can improve the NOx emissions by 5 to 40 percent for coal fired boilers.44 The actual NOx emission rate achieved is dependent on the difference between the optimal settings and the boiler settings being used before optimization.

(b) **Low Excess Air**

Low excess air (LEA) is a burner optimization strategy in which the boiler is operated at the lowest excess air 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.45 One notable advantage of this strategy is that no significant capital expenses for new or modified hardware are required.

With LEA, incomplete combustion may occur resulting in an increase in carbon content of boiler ash, a decrease in energy efficiency, a decrease in steam than 1%. Without a strict control system, these characteristics can also lead to temperature, and a significant increase in CO emissions when the O2 content is less slagging and corrosion, opacity concerns, and fires in air preheaters and ash hoppers.

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Staged Combustion (i.e., air staging and fuel staging)

Staged combustion relies on the reduction of the peak flame zone oxygen level to reduce formation of fuel NOx, and is achieved by delaying or staging the addition of combustion air.

(c) 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 the combustion process to create different zones. By distributing the air and staging the combustion, the flame temperature is 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.

(d) Fuel Staging

Staged fuel combustion can be accomplished using burners out of service (BOOS), biasing the fuel flow to 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 furnace 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 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.

(e) Fuel Reburn

Fuel reburn is a staged fuel combustion technique where fuel is introduced downstream of the primary combustion chamber in a boiler to create a secondary combustion zone. However, with fuel reburning, the NOx formed in the primary combustion area is destroyed in the reburn area. The fuel added can be any type of fuel, but most experience is with natural gas. Emission reductions of 35 to 60% are possible.46

Additions to Combustion Air or Fuel

Boiler operation can be optimized to reduce NOx emissions by injecting flue gases, water, steam, or other materials into the combustion zone. This controls the formation of NOx by controlling the stoichiometric ratio of the chemicals that react to form NOx. The addition of flue gas, water, or steam dilutes the combustion zone and reduces the combustion temperature, which in turn reduces the formation of thermal NOx.

(f) Flue Gas Recirculation (FGR)

FGR consists of recycling a portion of the flue gas back to the primary combustion zone. Heating of the inert flue gas in the primary combustion zone lowers the peak flame temperatures in the primary combustion zone and thereby lowers thermal NOx formation. In addition, the flue gas lowers the oxygen concentration in the primary combustion zone and thereby lowers thermal NOx.

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NOx. FGR technology is frequently used in conjunction with low NOx burner design. FGR reduces emissions of NOx in a natural gas boiler by about 53 to 74%.\(^47\)

(g) **Water / Steam Injection (WSI)**

With this technique, water or steam is injected into the primary combustion zone to reduce the formation of thermal NOx, but not fuel NOx, by decreasing the peak combustion temperature. More specifically, water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to vaporize the water (latent heat of vaporization) and raise the vaporized water temperature to the combustion temperature. WSI reduces NOx emissions by as much as 80% (in natural gas-fired units).\(^48\)

(h) **Fuel Induced Recirculation (FIR)**

FIR is a combustion control used in natural gas boilers. With FIR, flue gas is recirculated and mixed with the fuel. This technique cools the temperature similarly to how FGR reduces the temperature and thermal NOx is reduced. However, FIR also reduces prompt NOx. Prompt NOx is from the oxidation of compounds formed from reactions between atmospheric nitrogen and radicals formed in the combustion of fuel. For example, nitrogen monohydride, hydrogen cyanide, and other compounds can form during combustion and then be oxidized to nitric oxide.

**Low NOx Burners**

Low NOx burners emit less NOx than conventional burners. They are usually designed to incorporate one or more of the combustion control techniques discussed above within the burner, such as staged combustion, flue gas recirculation, fuel induced 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 NOx.

(i) **Low NOx Burners (LNB)**

LNB is a relative term that refers to a burner that has been designed to generate less NOx. It is relative in the sense that a LNB in a furnace that is several decades old may have a NOx emission rate of approximately 50 ppm, while a LNB on a new boiler may have a NOx emission rate of less than 30 ppm.\(^49\) LNB technology is available from many manufacturers and applicable to all fuels. Low NOx burners achieve 32 to 71% reduction.\(^50\)

The staging results in fuel-lean and fuel-rich combustion zones in the furnace at the burner. In the fuel-lean zones, the combustion temperature is lowered, reducing the production of NOx emissions. Both the temperature and oxygen concentrations are


lowered in the fuel-rich zones. LNB technology is available from many manufacturers and applicable to all fuels. Retrofitting older boilers with newer LNB can be technically feasible, but comes at a high capital cost. Compared to conventional burners, Low NOx burners achieve 32 to 71% reduction.51

Post Combustion Control

Post combustion control includes the addition of technologies that reduce NOx emissions (as opposed to preventing NOx generation). Generally, these technologies include the addition of a catalyst or reactant into the exhaust stream which chemically reduces the NOx, allowing for removal from the gas stream.

(j) Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) 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 with the following basic reaction pathways:

\[
4\text{NH}_3 + 4\text{NO} + \text{O}_2 > 4\text{N}_2 + 6\text{H}_2\text{O}
\]
\[
8\text{NH}_3 + 6\text{NO}_2 > 7\text{N}_2 + 12\text{H}_2\text{O}
\]

Depending on system design, NOx removal of 80-90% can be achieved under optimum conditions.52

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 in boilers, is typically designed to occur between 600°F and 750°F, depending on the catalyst.53 Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NOx molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NOx removal efficiency by increasing residence time, but will also cause an increase in catalyst bed pressure drop.

Reaction temperature is critical for proper SCR operation. Below the minimum temperature, reduction reactions will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NOx emissions.

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SCR catalyst can be subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation, if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium.

(k) **Selective Non-Catalytic Reduction**

Like SCR, SNCR operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires an exhaust of 1600-2000°F.

Depending on system design, NOx removal of 25-50% can be achieved under optimum conditions in utility boilers, and 30-70% in industrial boilers.

(l) **Regenerative Selective Catalytic Reduction (RSCR)**

Regenerative Selective Catalytic Reduction (RSCR) is similar to SCR in that it operates by promoting the conversion of NOx into molecular nitrogen and water vapor using urea or ammonia. As noted above, SCR systems typically operate at approximately 600-750°F for the destruction of NOx. In some cases, a gas stream may be routed to particulate matter collection device or other control following exit of the furnace; in this case, the stream is significantly cooled, which may reduce the effectiveness of a catalyst. RSCR introduces a regenerative heater (similar to that used in a regenerative thermal oxidizer) prior to routing to an SCR. The temperature of the flue gas is temporarily elevated to improve catalyst performance, and the heat is recovered before sending the clean flue gas to the stack. These systems are primarily used for tail-end/low temperature applications where the flue gas is relatively cool, with low levels of particulates and acid gases. Such systems have been demonstrated to achieve a NOx reduction efficiency >80%, when applied to a cold gas (e.g., after boiler and scrubber/particulate removal equipment). It is currently applied in biomass plants for small boiler applications.

**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.

(m) **Fuel Switching**

Nitrogen concentrations in fuel have a large impact on total NOx emissions from fuel combustion in boilers. Replacing high-nitrogen fuels with low-nitrogen fuels, such as distillate oil or natural gas, can be an effective means in reducing NOx. Low-nitrogen fuels can be used to displace a fraction of the boiler combustion fuel, or replace it entirely. Either means of reducing the use of high-nitrogen fuels can result in significant NOx emissions.

**Step 2 – Eliminate Technically Infeasible Control Options**

A number of the control options identified are not technically feasible for controlling NOx at for the four (4) natural gas and coke oven fired boilers [B001, B002, B003, and B004]. A review of available controls identified low NOx burners, selective catalytic reduction, and selective non-catalytic reduction as technically feasible controls. This section presents the rationale explaining why each control option is, or is not, technically feasible for the four boilers.
(a) **Combustion Optimization**

Combustion optimization and operating and maintenance (O&M) practices are applicable to all types of boilers combusting all types of fuels. Such practices are generally used throughout the industry to increase energy efficiency and lower fuel costs, as well as pollutant emissions. Currently, U.S. Steel – Irvin Plant is required to operate and maintain Boilers No. 1 through 4 in accordance with the good combustion and air pollution control practices, per RACT Order No. 258. Additionally, U.S. Steel –Irvin Plant is currently required to conduct an annual tune-up, including inspection, adjustment, cleaning, or necessary 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 inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation, per RACT Order No. 258. Although these requirements may not include all of the adjustments and optimizations that would be conducted during a full combustion optimization they would address several of the issues and make the emission reduction effectiveness of a full optimization even more uncertain. Therefore, combustion/performance optimization practices are considered technically feasible for the boilers, but the additional emission reductions cannot be predicted and they would be expected to be relatively low since the source is already performing many of the optimization activities.

(b) **Low Excess Air**

Low excess air (LEA) is a burner optimization strategy in which the boiler is operated at the lowest excess air 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. Boilers No. 1 through 4 already have low excess air (LEA) in the exhaust stream (less than 5%). Boilers No. 1 through 4 windbox and burner designs currently produce NOx emissions comparable to rates for boilers using ULNB/LNBs with FGR. Therefore, LEA is considered technologically feasible for Boilers No. 1 through 4, but no additional emission reductions would result because the source is already performing this activity.

(c) **Staged Combustion (i.e., air staging and fuel staging)**

Over-fire air (OFA) is a combustion design in which a controlled portion of the combustion airflow is diverted to injection ports beyond the last row of burners. Over-fire air is considered to be technically feasible for Boilers No. 1 through No. 4, as it has previously been used in similar types of units.

Use of BOOS is not applicable to single-burner packaged watertube boilers54; therefore, use of BOOS is not technically feasible for Boilers No. 1 through 4.

(d) **Fuel Reburning**

Reburning has been chiefly developed and applied in coal-fired boilers. Typically natural gas is introduced downstream of the primary combustion chamber to create a secondary combustion zone. Boilers No. 1 through 4 are currently coke oven and

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natural gas fired, which are nitrogen-free fuels. Therefore, fuel re-burn is considered technically infeasible for controlling NOx emissions.

(e) **Flue Gas Recirculation**

FGR involves the recirculation of a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. FGR is considered to be technically feasible for Boilers No. 1 through No. 4, as it has previously been used in similar types of units. However, based on information provided by the source, Boilers No. 1 through 4 windbox and burner designs currently produce NOx emissions comparable to rates for boilers using ULNB/LNBs with FGR. Therefore, a limited reduction in emissions would be anticipated from the use of FGR.

(f) **Water/Steam Injection**

WSI can control NOx, but it has severe 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 is much less than on a steam boiler. Therefore, WSI is considered technically infeasible for controlling NOx emissions.

(g) **Fuel Induced Recirculation (FIR)**

EPA’s RBLC (RACT-BACT-LAER Clearinghouse) shows only a single industrial sized natural gas fired boiler equipped with an FIR for NOx control on over the last 10 years. Therefore, FIR is removed from further consideration.

(h) **Low NOx Burners**

Low NOx Burner (LNB) technology is available from many manufacturers and applicable to all fuels. LNBs have previously been installed in similar boilers, and have been shown to be effective in reducing NOx emissions in similar types of boilers. Boilers No. 1 through 4 windbox and burner designs currently produce NOx emissions comparable to rates for boilers using ULNB/LNBs with FGR. LNBs are considered technically feasible for Boilers No. 1 through 4. Each burner would need to be replaced with a burner of similar size and design (i.e., flame speed, temperature length, heat output).

(i) **Selective Catalytic Reduction**

SCR controls NOx emissions by promoting the conversion of NOx into molecular nitrogen and water vapor using a catalyst. SCR units have been used on boilers that are similar to the natural gas and COG fired boilers in similar facilities in the United States. For this reason, SCR is considered to be technically feasible for Boilers No. 1 through No. 4. SCR is expected to be capable of reducing NOx emissions by 80% due to low excess air in the exhaust of this operation (less than 5%). Exhaust gases would have to be preheated prior to treatment.

(j) **Selective Non-Catalytic Reduction**

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55 The following RBLC Codes were included in the search: 12.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces size 100-250 MMBtu/hr; Natural Gas) and 13.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces <100 and MMBtu/hr; Natural Gas.)
SNCR is similar to SCR, but it does not use a catalyst. SNCR units have been used on similar natural gas and COG fired boilers in facilities in the United States. For this reason, SNCR is considered to be technically feasible for Boilers No. 1 through 4. SNCR is expected to be capable of reducing NOx emissions by 45%. Exhaust gases would have to be preheated prior to treatment.

(k) **Regenerative Selective Catalytic Reduction (RSCR)**

RSCR has not been used on boilers in the United States. Instead, this technology has largely been used at biomass plants in small boiler applications. Extensive research and pilot testing are needed to determine whether this technology is feasible for boilers or for COG applications. For this reason, RSCR is not considered to be technically feasible for Boilers No. 1 through 4.

(l) **Fuel Switching**

Fuel switching from a COG/NG mixture to 100% natural gas could result in reduced emissions of NOx. However, U.S. Steel previously developed a system to utilize COG for its blast furnaces, boilers for all of its Mon Valley Works operations. The current system includes a COG processing facility at the U.S. Steel – Clairton Works, a coke plant, which processes the COG until its content is approximately 50-60 percent hydrogen. The COG/natural gas mixture is subsequently piped to the U.S. Steel – Edgar Thomson and U.S. Steel – Irvin Plant operations, where it is used in reheat/annealing furnaces, boilers, and in collocated facilities.

The COG is partially supplemented with natural gas to enrich certain properties that are needed to operate the various equipment. Because the COG/natural gas mixture is optimized to operate the various furnaces, the COG concentration in the gas mixture cannot be increased. Therefore, fuel switching from a COG/NG mixture to 100% natural gas is not considered a technically feasible option for Boilers No. 1 through 4.

**Step 3 - Evaluate Control Options**

**Emissions and Emission Reductions**

The table below shows the emissions from Boilers No. 1 through 4, the technically feasible control options for these units, and the estimated control efficiency of each control option.

The technically feasible control options with their estimated control efficiency are as follows:

**Table 8. Boilers No. 1 through 4 – NOx Control Options**

<table>
<thead>
<tr>
<th>Unit(s)</th>
<th>Potential to Emit NOx (tpy)</th>
<th>Control Type</th>
<th>Estimated NOx Control Efficiency (%)</th>
<th>Controlled NOx Emissions (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler No. 1 (79.8 MMBtu/hr)</td>
<td>55.92&lt;sup&gt;a&lt;/sup&gt;</td>
<td>LNB</td>
<td>50&lt;sup&gt;a&lt;/sup&gt;</td>
<td>0.08</td>
</tr>
<tr>
<td></td>
<td></td>
<td>FGR/OFA</td>
<td>40&lt;sup&gt;f&lt;/sup&gt;</td>
<td>0.064</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCR</td>
<td>80&lt;sup&gt;g&lt;/sup&gt;</td>
<td>0.032</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45&lt;sup&gt;g&lt;/sup&gt;</td>
<td>0.088</td>
</tr>
<tr>
<td>Boiler No. 2 (84.6 MMBtu/hr)</td>
<td>59.29&lt;sup&gt;a&lt;/sup&gt;</td>
<td>LNB</td>
<td>50&lt;sup&gt;a&lt;/sup&gt;</td>
<td>0.08</td>
</tr>
<tr>
<td></td>
<td></td>
<td>FGR/OFA</td>
<td>40&lt;sup&gt;f&lt;/sup&gt;</td>
<td>0.06</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCR</td>
<td>80&lt;sup&gt;g&lt;/sup&gt;</td>
<td>0.032</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNCR</td>
<td>45&lt;sup&gt;g&lt;/sup&gt;</td>
<td>0.088</td>
</tr>
<tr>
<td>Boiler No. 3 (41.6)</td>
<td>29.15&lt;sup&gt;c&lt;/sup&gt;</td>
<td>LNB</td>
<td>50&lt;sup&gt;a&lt;/sup&gt;</td>
<td>0.12</td>
</tr>
</tbody>
</table>
Economic Analysis

Using information provided by U.S. Steel – Irvin Plant and collected by ACHD, thorough economic analyses of the technically feasible control options for Boilers No. 1 through 4 was conducted - see Appendix D for more information. The analyses estimate 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, except for direct installation costs, were calculated using the methodology described in Section 6, Chapter 1 of the “EPA Air Pollution Control Cost Manual, Sixth Edition” (document # EPA 452-02-001). Direct capital cost is based on a vendor quote. Annualized costs are based on an interest rate of 7% and an equipment life of 20 years.

The basis of cost effectiveness, used to evaluate the control option, is the ratio of the annualized cost to the amount of NOx (tons) removed per year. A summary of the cost figures determined in the analysis for each unit is provided in the table below:

| Boiler No. 1 | LNB | $732,981 | $91,178 | 28 | $3,261 |
**Step 4 – Select RACT**

Based on the costs shown in Table 9, installing FGR or OFA are cost effective NOx control options for Boilers No. 1 through 4. The use of LNB, SCR, or SNCR is much more costly.

ACHD reviewed the EPA’s RBLC determinations for natural gas boilers less than 100 MMBtu/hr. Specifically, the ACHD reviewed 17 boilers, representing 12 facilities, listed under the RBLC Code 13.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces <100 MMBtu/hr; Natural Gas). Table 10 provides the RBLC findings.

**Table 10. Boilers < 100 MMBtu/hr – EPA’s RBLC Findings**

<table>
<thead>
<tr>
<th>Source</th>
<th>RBLC ID</th>
<th>Date of Permit Issuance</th>
<th>NOx Limit (lb/MMBtu)</th>
<th>NOx Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interstate Power &amp; Light [60 MMBtu/hr]</td>
<td>IA-0107</td>
<td>4/14/14</td>
<td>0.013 (test avg)</td>
<td>-</td>
</tr>
<tr>
<td>Holland Public Works [55 MMBtu/hr]</td>
<td>MI-0412</td>
<td>12/4/13</td>
<td>0.05 (test avg)</td>
<td>LNB+GCP</td>
</tr>
<tr>
<td>Holland Public Works [95 MMBtu/hr]</td>
<td>MI-0138</td>
<td>12/13/13</td>
<td>0.05 (test avg)</td>
<td>LNB+FGR+GCP</td>
</tr>
<tr>
<td>Consumers Energy Co [100 MMBtu/hr]</td>
<td>MI-0410</td>
<td>7/25/13</td>
<td>0.05 (test avg)</td>
<td>LNB+FGR</td>
</tr>
<tr>
<td>Arcadis, US, Inc. [99 MMBtu/hr]</td>
<td>OH-0352</td>
<td>6/18/13</td>
<td>0.055 (test avg)</td>
<td>LNB+FGR</td>
</tr>
<tr>
<td>Hickory Run Energy Station [40 MMBtu/hr]</td>
<td>PA-0291</td>
<td>4/23/13</td>
<td>0.011 (test avg)</td>
<td>-</td>
</tr>
<tr>
<td>Klausner Holding USA [46 MMBtu/hr] (4 units)</td>
<td>SC-0149</td>
<td>1/3/13</td>
<td>0.036 (test avg)</td>
<td>-</td>
</tr>
</tbody>
</table>
Although the RBLC data reflects boilers burning natural gas with a much lower lb/MMBtu limit, the use of COG in the reheat furnaces is expected to produce a higher level of NOx, therefore, a limit of 0.06 lb/MMBtu is considered achievable. Therefore, ACHD considers FGR or OFA meeting an emission rate of 0.06 lb/MMBtu to be considered RACT for Boilers No. 1 through 4.

### F. RACT for VOC – Five (5) 140 MMBtu/hr 80-inch Hot Strip Mill Reheat Furnaces [P001-P005]

Five (5) direct-fired reheat furnaces used to reheat incoming slabs prior to hot rolling on the scale breaking/roughing and finishing mill stands; each rated at 140 MMBtu/hr fuel input and capable of processing 3,000,000 tons of sheet per year. The Hot Strip Mill Reheat furnaces are fired with natural gas-enriched coke oven gas, which is piped in from a nearby coke production facility; emissions exhaust to stacks SP1 through SP6. Emissions are uncontrolled.

The Title V operating permit, condition V.A.1.a, states that "Only coke oven gas and natural gas shall be combusted in reheat furnaces No. 1 through No. 5." [§2103.12.h.5.D]

Also, the Title V operating permit, condition V.A.1.g, states that VOC emissions from each Hot Strip Mill Reheat Furnaces No. 1 through No. 5 shall not exceed 0.34 lb/hr when combusting coke oven gas and 0.89 lb/hr when combusting natural gas. Total annual emissions are limited to 3.88 tons per year per furnace (19.4 tons per year).

### Step 1 – Identify Control Options

ACHD reviewed U.S. Steel – Ivirn's RACT submittal for the five (5) Hot Strip Mill Reheat furnaces and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA’s Control Techniques Guidelines (CTG) document for Volatile Organic Emissions from Stationary Sources. 56 EPA’s “Control Technologies for Hazardous Air Pollutants”, 57 background information for the NESHAP for Integrated Iron and

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Steel Plants, and investigated additional resources to determine if any other VOC controls for reheat furnaces or other stationary external combustion sources have been demonstrated since the CTG document was published. The identified controls are discussed below.

The CTG document identifies the following controls for stationary external combustion sources:

1. Good combustion practices

U.S. Steel – Irvin Plant also reviewed the following controls:

2. Thermal oxidation
3. Carbon Adsorption
4. Condensation

ACHD additionally reviewed common VOC control techniques for similar stationary sources. This included the review of the following controls:

5. Routing to a Boiler
6. Routing to a Flare
7. Combustion/Performance Optimization

These controls are discussed in detail below.

(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°F 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 organic vapor removal efficiencies in excess of 95 percent.59

(b) **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

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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.\textsuperscript{60}

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.

(c) \textbf{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.\textsuperscript{61} 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.\textsuperscript{62}

(d) \textbf{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. The effectiveness of carbon adsorption is largely dependent on available carbon sites.

(e) Condensers

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 later, 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 volatile organic emissions. 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 condenser is directly related to 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.

(f) Combustion/Performance Optimization

Operating and maintenance (O&M) practices have a significant impact on furnace performance, including VOC emissions, reliability, and operating costs. Each of these parameters change over the life of the furnace, and some deterioration of equipment is unavoidable. VOC emissions from furnaces 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:

- 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;
- Optimization of total emissions of CO, which is used as a surrogate for combustion efficiency. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject;

An energy efficiency assessment (aka energy efficiency audit) typically serves as the foundation for furnace efficiency improvements by providing an evaluation of actual boiler 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 generally includes:

- A visual inspection of the furnace system.
- An evaluation of operating characteristics of the furnace, 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) has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion.64

Step 2 – Eliminate Technically Infeasible Control Options

A review of available controls identified no technically feasible controls for controlling VOC from the five (5) direct-fired reheat furnaces. This section presents the rationale explaining why each control option is not, technically feasible.

(a) Thermal Oxidation (TO)

The VOC emissions from the five (5) reheat furnaces are associated with the by-products of combustion. VOCs associated with combustion are generally present in very low concentrations, provided that efficient fuel combustion practices are performed. The low concentrations of VOCs that remain generally have a higher molecular weight and boiling point, therefore, they are normally more difficult to control.

In general, if the VOC emissions in the exhaust stream of a gas are below the minimum VOC concentration that a control device is capable of controlling, then the control device is not considered feasible. EPA literature indicates that, for thermal oxidizers, inlet concentrations of VOC/HAPs below ~20 ppm cannot be reduced consistently or to any given predicted concentration.65 The concentration of VOC in the exhaust stream from the five (5) reheat furnaces is less than 0.4 ppm. Therefore, the use of an TO is considered not technically feasible for the reheat furnaces.

(b) Routing to Boiler

The facility has existing Boilers No. 1 through 4, which provide heat and steam for pickling operations and the galvanizing and galvalume lines. Although it may be possible to route emissions from the reheat furnaces to one of the existing boilers, given the low concentration of VOC in the exhaust stream of the reheat furnaces (which exhausts at a temperature of ~2400°F), and the temperatures of the existing boilers (700°F), it is not anticipated that the secondary combustion provided by the

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64 From proposed National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers. (75 FR 31907, June 4, 2010).
boilers would result in any measurable reductions of VOC. As noted above, the VOCs that remain in the exhaust stream from the reheat furnaces are likely to a higher molecular weight and boiling point than could be controlled with the existing boilers.

(c) Routing to a Flare

The facility has four existing flares (three (3) Coke Oven Gas Flares and the Peachtree flare), which are currently used to control excess coke oven gas not otherwise combusted in the existing furnaces at the facility. Flaring is currently limited to periods when a major operation or source is inactive. Although it may be possible to route emissions from the reheat furnaces to the flares, given the low concentration of VOC in the exhaust stream (less than 0.4 ppm), flaring is not anticipated to result measurable VOC emissions reductions.

(d) Carbon Adsorption

Carbon adsorption is not considered technically feasible for the five (5) reheat furnaces. As discussed for the TO option, the concentration of VOC in the exhaust stream from the five (5) reheat furnaces is less than 20 ppm. In general, a carbon adsorber requires an inlet concentration stream of at least 1,000 ppm VOC to be effective.66 As such, the use of a carbon adsorber would not result in a measurable reduction of VOC. Additionally, carbon adsorbers generally require the exhaust gas temperature to be within a range of 100-200°F, which is significantly lower than the exhaust temperature of the reheat furnace(s) exhaust. Finally, if an adsorber were applied, the resulting pressure drop could result in additional costs if a larger fan were required. Therefore, the use of a carbon adsorber is considered not technically feasible for the reheat furnaces.

(e) Condensers

A condenser is not considered technically feasible for the five (5) reheat furnaces. As discussed for the TO option, the concentration of VOC in the exhaust stream from the five (5) reheat furnaces is less than 20 ppm. In general, a condenser requires an inlet concentration stream of at least 5,000 ppm VOC to be effective.67 As such, the use of a condenser would not result in a measurable reduction of VOC. Additionally, condensers generally require the exhaust gas temperature to be within a lower temperature range, usually requiring refrigeration to temperatures approaching -100°F.68 This is significantly lower than the exhaust temperature of the reheat furnaces; therefore a condenser could not be applied with significant, and likely costly, energy removal. Therefore, the use of a condenser is considered not technically feasible for the reheat furnaces.

(f) Combustion/Performance Optimization

Combustion optimization and operating and maintenance (O&M) practices are applicable to all types of furnaces combusting all types of fuels. Such practices are generally used throughout the industry to increase energy efficiency and lower fuel costs, as well as pollutant emissions. Currently, U.S. Steel – Irvin Plant is required to operate and maintain the Hot Strip Mill Reheat Furnaces in accordance with the good

66 Id.
67 Id.
combustion and air pollution control practices, per RACT Order No. 258. Additionally, U.S. Steel –Irvin Plant is currently required to conduct an annual tune-up, including inspection, adjustment, cleaning, or necessary 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 inspection of the air-to-fuel ration control system and adjustments necessary to ensure proper calibration and operation, per RACT Order No. 258. Therefore, combustion/performance optimization practices are considered technically feasible for the Hot Strip Mill Reheat Furnaces, but no additional emission reductions would result because the source is already performing this activity.

**Step 3 - Evaluate Control Options**

**Emissions and Emission Reductions**

The VOC emissions from Hot Strip Mill Reheat Furnaces No. 1 through No. 5 are limited to 0.34 lb/hr each when combusting coke oven gas and 0.89 lb/hr each when combusting natural gas. The total annual emissions are limited to 3.88 tons per year per furnace, or 19.4 tons per year for all furnaces. Although combustion/performance optimization practices are considered technically feasible for the Hot Strip Mill Reheat Furnaces, no additional emission reductions are expected.

**Economic Analysis**

Because the source is currently performing combustion/performance optimization practices, no additional costs are anticipated.

**Step 4 – Select RACT**

The five (5) Hot Strip Mill Reheat Furnaces are already subject to the good combustion requirements of Article XXI; therefore, it was determined that RACT for these furnaces is no additional control, the existing limit on VOC emissions of 3.88 tpy per furnace, and compliance with Article XXI.

**G. RACT for VOC – 80-inch Hot Strip Mill Roughing and Finishing Mill [P016] and No.3 Five Stand Cold Reduction Mill [P008]**

This section includes a single VOC RACT analysis for the 80-inch Hot Strip Mill Roughing and Finishing Mill [P016] and No.3 Five Stand Cold Reduction Mill [P008] because these units have a similar design and function, use rolling oils for lubrication, and are expected to have similar emission profiles.

**Hot Strip Mill Roughing and Finishing Mill**

Heated steel slabs from the 80-inch Hot Strip Mill Furnaces are hot rolled on the Scale Breaker/Roughing Mill and Finishing Mill [P016]; the mill stands have a design production rating of 3,000,000 tons sheet/yr. The hot strip mill uses rolling oil/water emulsions to lubricate the rolls and to reduce friction between the slab and the rolls. VOC emissions are present due to the use of rolling oil; emissions are uncontrolled. The oils are discharged indoors as fugitive emissions from the operation, and there are no dedicated exhaust points. The potential to emit of VOC from these operations is 30 tons per year, based on a consumption of 750 tons of rolling oil per year and a VOC content of 4%.
The Title V operating permit, condition V.A.1.f, states that “The permittee shall operate the 80” Hot Strip Mill scale breaking/roughing and finishing mill stands with lubricating oil, which is an oil-water emulsion and does not exceed a maximum VOC content by weight, of 4%, at any time.” [RACT Order No. 258; §2105.06]

**No. 3 Five Stand Cold Reduction Mill**

The No. 3 Five Stand Cold Reduction Mill consists of a steel roll uncoiler, five mill stands, hydraulic shear, and a roll coiler; the mill stands have a maximum capacity of 2,500,000 tons of steel coils per year. Cold reduction is the process of passing unheated metal though a series of rolls for the purpose of reducing its thickness, smoothing its surface, and improving mechanical properties. The process creates friction and generates heat, which is dissipated by a system of flood lubrication (oil in water emulsion) that is directed in stream against the rolls. VOC emissions are generated in the heat transfer process.

The units are controlled for VOC and particulate matter by a particulate (oil mist) capture system with approximately 99.9% capture efficiency and 5 cyclone mist eliminators in series with an approximate control efficiency of 97%.

The Title V operating permit, condition V.D.1.a, states that, “The Permittee shall not operate, or allow to be operated, the cold reduction mill unless the five mill stands are equipped with a capture system that exhausts to a mist eliminator control system. The collection and control system shall be properly maintained and operated, treating all oil mist emissions from the cold reduction mill, according to the following specifications while the line is in operation:

1) The capture system shall have a negative air flow into the system at all times and partially enclose the mill stands with openings for the steel sheet inlet and outlet and openings for observation and access to the rollers and steel.
2) The mist eliminator control system shall be comprised of five identical cyclone mist eliminators, in parallel with a design minimum combined air flowrate of 200,000 ACFM.
3) The North and South fans shall maintain an inlet static pressure that is no more negative than -8.0” w.c.” [Installation Permit No. 0050-I002a, and §2102.04.b.6]

The Title V operating permit, condition V.D.1.b states that, “The Permittee shall conduct cleaning of the cyclone mist eliminators specified in Condition V.D.1.a above once every four months. This cleaning will be conducted in such a way as to thoroughly remove all material or corrosion that could decrease the mist eliminator efficiencies. Notwithstanding the previous, cleaning shall be conducted immediately following any inspection of the mist eliminators as specified in Condition V.D.3.a below if warranted by the inspection findings or when a measured inlet pressure exceeds Condition V.D.1.a.3) above.” [Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

Title V operating permit condition V.D.1.c states “The Permittee shall not operate or allow to be operated, the cold reduction mill in such a manner that the production during any 12 consecutive months exceeds 2,500,000 tons of steel or the daily average hourly production rate exceeds 525 tons of steel per hour based on the number of hours of operation in a day.” [Installation Permit No. 0050-I002a]

Title V operating permit condition V.D.1.d states “The permittee shall not operate the Cold Reduction Mill with a lubricating oil VOC content, by weight greater than 2% and a water-oil emulsion oil content, by volume greater than 7%, at any time. [RACT Order No. 258, §2105.06]
Finally, Title V operating permit condition V.D.1.e states that VOC emissions from the cold reduction mill shall not exceed 0.025 tons per ton steel rolled, 13.12 lbs per hour, or 31.25 tons per year. [Installation Permit No. 0050-I002a, February 12, 2004 and §2102.04.b.6]

**Step 1 – Identify Control Options**

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the 80-inch Hot Strip Mill Roughing and Finishing Mill and No.3 Five Stand Cold Reduction Mill and consulted several references to ensure that all possible control options were identified. ACHD reviewed the RBLC, EPA’s CTG for Volatile Organic Emissions from Stationary Sources 69, EPA’s “Control Technologies for Hazardous Air Pollutants”,70 and investigated additional resources to determine if VOC controls for rolling mills have been demonstrated. The CTG document does not identify any controls for roughing and finishing or rolling mill stands at iron and steel facilities. U.S. Steel – Irvin Plant also reviewed the following controls:

1. Mist Eliminators
2. Thermal Oxidizer
3. Oil Substitution

No additional VOC control measures were identified for the Roughing and Finishing Mill or the Cold Reduction Mill. These controls are discussed in detail below.

(a) **Mist Eliminator and Enclosure**

Mist eliminators work by utilizing composite mesh or vane plate surfaces to separate the mist droplets from gas streams through mechanical impingement and the inertial impaction of droplets onto a stationary set of blades or a mesh pad. In some cases, if cooling is required to condense the organic vapor, an optional heat exchanger is included. Mist eliminators typically are operated as dry units that are periodically washed down with water to clean the impaction media. In some cases, the collected organic liquid drains into the bottom of the housing and is removed by a gravity drain or optional powered pump out. Some manufacturers claim an efficiency as high as 99%. An enclosure is usually required to capture the emissions generated during oil evaporation.

(b) **Thermal Oxidizer**

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 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

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incoming VOC-laden stream to improve the efficiency of the oxidizer. Thermal oxidizers can achieve a wide range of efficiencies, and usually achieve organic vapor removal efficiencies in excess of 95 percent.\textsuperscript{71}

(c) **Oil Substitution**

Oil substitution is not considered a VOC control technique, but more of a pollution prevention or source reduction technique. When considering the lubricants used in the rolling process, the physical properties that affect the amount of VOC that results from vaporization are vapor pressure, specific heat, and heat of vaporization. An oil with higher vapor pressure implies a shorter chain length of hydrocarbons and thus a lower molecular weight. This allows higher lubricant evaporation during the rolling process when compared to a lubricant with lower vapor pressure. For reducing emissions, an oil with a relatively low vapor press (less than 1 mmHg) and high specific heat and heat of vaporization properties is preferred. These properties result in reduced vapor generation and greater capture control of the oil.

### Step 2 – Eliminate Technically Infeasible Control Options

A review of available controls identified no additional technically feasible controls for controlling VOC from the 80-inch Hot Strip Mill Roughing and Finishing Mill and No.3 Five Stand Cold Reduction Mill. This section presents the rationale explaining why each control option is not, technically feasible.

(a) **Mist Eliminator and Enclosure**

Mist eliminators separate the mist droplets from gas streams. Unlike the cold rolling operations, the hot strip mill rolling involves rolling heated steel slabs from the 80-inch Hot Strip Mill Furnaces. The use of the oil/water emulsion at the much higher temperatures makes the use of mist eliminators and similar filtration systems not effective in oil reduction. Additionally, significant enclosures, hoods, and ducting would need to be installed, which are anticipated to significantly increase costs. Therefore, a mist eliminator is not considered technically feasible for the Hot Strip Mill Roughing and Finishing.

The No. 3 Five Stand Cold Reduction Mill is currently controlled for VOC and particulate matter by a particulate (oil mist) capture system with approximately 99.9% capture efficiency and 5 cyclone mist eliminators in series with an approximate control efficiency of 97%. Therefore, although a mist eliminator is considered technically feasible for the Cold Reduction Mill, no additional emissions reductions are anticipated since they are currently using this technology.

(b) **Thermal Oxidizer**

A thermal oxidizer is not considered to be technically feasible for the Hot Strip Mill Roughing and Finishing and . The current use of an oil/water emulsion means that the majority of the mist from the operation is water. As such, a thermal oxidizer would need to be significantly large to control the operations.

The No. 3 Five Stand Cold Reduction Mill has a VOC concentration in the exhaust stream of less than 4 ppm. EPA literature indicates that, for thermal oxidizers, inlet

concentrations of VOC/HAPs below ~20 ppm cannot be reduced consistently or to any given predicted concentration. Additionally, a thermal oxidizer would destroy the VOC rather than recovering it; currently, a large portion of the VOC is reclaimed and reused. Therefore, a thermal oxidizer is not considered technically feasible for the No. 3 Five Stand Cold Reduction Mill.

(c) **Oil Substitution**

The use of an oil/water emulsion in the Hot Strip Mill Roughing and Finishing operations are currently limited to those that contain no more than 4% by weight VOCs. The current emulsions used by U.S. Steel – Irvin Plant is Rollshield 6301. The VOC content of this emulsion is 4.0%. U.S. Steel – Irvin Plant is not aware of oils with a lower VOC content that can be applied to the rolling mills at this time. Therefore, oil substation is not considered technically feasible for the Hot Strip Mill.

The use of an oil/water emulsion in the No. 3 Five Stand Cold Reduction Mill is currently limited to a lubricating oil VOC content of not greater than 2% by weight and a water-oil emulsion oil content not greater than 7% by volume. For Stands 1-4, the current water-oil emulsion oil content is 5% by volume. For Stand 5, the current water-oil emulsion oil content is 2% by volume. U.S. Steel – Irvin Plant is not aware of oils with a lower VOC content that can be applied to the Cold Reduction mills that would offer the same product quality performance. Therefore, oil substation is not considered technically feasible for the Cold Reduction Mill.

**Step 3 - Evaluate Control Options**

**Emissions and Emission Reductions**

No control options were found to be technically feasible for the Hot Strip Mill Roughing and Finishing operations. Although a mist eliminator and enclosure are considered technically feasible for the No. 3 Five Stand Cold Reduction Mill, no additional emission reductions are expected.

**Economic Analysis**

Because the source is currently using a mist eliminator/enclosure for the No. 3 Five Stand Cold Reduction Mill, no additional costs are anticipated.

**Step 4 – Select RACT**

No additional controls were identified as technically feasible for the Hot Strip Mill Roughing and Finishing or the No. 3 Five Stand Cold Reduction Mill. Therefore, it was determined that RACT for these furnaces is no additional control beyond what is currently required.

U.S. Steel – Irvin Plant is currently limited to operating the 80" Hot Strip Mill scale breaking/roughing and finishing mill stands with lubricating oil which is an oil-water emulsion and does not exceed a maximum VOC content by weight, of 4%, at any time.

U.S. Steel – Irvin Plant is currently limited to operating the Cold Reduction Mill with a lubricating oil with a VOC content no greater than 2% by weight and a water-oil emulsion oil content no greater than 7% by volume. U.S. Steel – Irvin Plant is also currently required to operate the cold reduction mill with the equipped enclosure and mist eliminator control system.

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The Title V operating permit condition V.D.1.e also states that VOC emissions from the cold reduction mill shall not exceed 0.025 tons per ton steel rolled, 13.12 lbs per hour, or 31.25 tons per year. [Installation Permit No. 0050-I002a, February 12, 2004 and §2102.04.b.6]

**H. RACT for VOC – Thirty-one (31) HPH Annealing Furnaces [P009]**

This section includes a single VOC RACT analysis for the thirty-one (31) HPH Annealing Furnaces because these units have a similar design and function, combust the same fuels, and are expected to have similar emission profiles.

The HPH Annealing Process consists of 31 individual movable furnaces with 58 bases in one unit that treat coiled steel rolls. Each furnace is fired with coke oven gas enriched with natural gas and has a maximum heat input rating of 4.9 MMBtu/Hr; emissions exhaust to stack SP10. Emissions are uncontrolled.

The Title V operating permit, condition V.E.1.a, states that "The HPH Annealing Furnaces shall only combust coke oven gas and natural gas." [§2102.04.b.5].

The Title V operating permit, condition V.E.1.e, states that emissions from HPH furnaces No. 1 through No. 31, shall not exceed the following [§2104.02.d.1, §2104.03.a.2.A and §2105.21.h.4]:

<table>
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<th>Pollutant</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr (each unit)</th>
<th>tons/yr (combined)</th>
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</thead>
<tbody>
<tr>
<td>VOC</td>
<td>0.03</td>
<td>0.01</td>
<td>0.14</td>
<td>4.21</td>
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</table>

**Step 1 – Identify Control Options**

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the thirty-one (31) HPH Annealing Furnaces and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA’s CTG document for Volatile Organic Emissions from Stationary Sources, EPA’s “Control Technologies for Hazardous Air Pollutants”, background information for the NESHAP for Integrated Iron and Steel Plants, and investigated additional resources to determine if any other VOC controls for annealing furnaces or other stationary external combustion sources have been demonstrated since the CTG document was published. The identified controls are discussed below.

The CTG document identifies the following controls for stationary external combustion sources:

1. Good combustion practices

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U.S. Steel – Irvin Plant also reviewed the following controls:

2. Thermal oxidation  
3. Carbon Adsorption  
4. Condensation  

ACHD additionally reviewed common VOC control techniques for similar stationary sources. This included the review of the following controls:

5. Routing to a Boiler  
6. Routing to a Flare  
7. Combustion/Performance Optimization  

No additional VOC control measures were identified for the annealing furnaces. These controls are discussed in detail below.

(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°F 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. 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.  

(b) 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.  

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77 Id.
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.

(c) 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. 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.

(d) 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. The effectiveness of carbon adsorption is largely dependent on available carbon sites.

(e) Condensers

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

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78 Id.
79 Id.
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 later, 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 volatile organic emissions. 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 condenser is directly related to 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. 

(f) Combustion/Performance Optimization

Operating and maintenance (O&M) practices have a significant impact on furnace performance, including VOC emissions, reliability, and operating costs. Each of these parameters change over the life of the furnace, and some deterioration of equipment is unavoidable. VOC emissions from furnaces 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:

- 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;
- 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 NOx requirement to which the unit is subject;

An energy efficiency assessment (aka energy efficiency audit) typically serves as the foundation for furnace efficiency improvements by providing an evaluation of actual boiler 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 furnace system.
- An evaluation of operating characteristics of the furnace, 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) has conducted energy assessments at selected
manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion.81

**Step 2 – Eliminate Technically Infeasible Control Options**

A review of available controls identified no additional technically feasible controls for controlling VOC from the thirty-one (31) HPH Annealing Furnaces. This section presents the rationale explaining why each control option is, or is not, technically feasible.

(a) **Thermal Oxidation (TO)**

The VOC emissions from the thirty-one (31) HPH Annealing Furnaces are associated with the by-products of combustion. VOCs associated with combustion are generally present in very low concentrations, provided that efficient fuel combustion practices are performed. The low concentrations of VOCs that remain generally have a higher molecular weight and boiling point, therefore, they are normally more difficult to control.

In general, if the VOC emissions in the exhaust stream of a gas are below the minimum VOC concentration that a control device is capable of controlling, then the control device is not considered feasible. EPA literature indicates that, for thermal oxidizers, inlet concentrations of VOC/HAPs below ~20 ppm cannot be reduced consistently or to any given predicted concentration.82 The concentration of VOC in the exhaust stream from the thirty-one (31) HPH Annealing Furnaces are well below 20 ppm. Therefore, the use of a TO is considered not technically feasible for these furnaces.

(b) **Routing to Boiler**

The facility has existing Boilers No. 1 through 4, which provide heat and steam for pickling operations and the galvanizing and galvalume lines. Although it may be possible to route emissions from the annealing furnaces to one of the existing boilers, given the low concentration of VOC in the exhaust stream of the annealing furnaces (which exhausts at ~800°F), and the temperatures of the existing boilers (700°F), it is not anticipated that the secondary combustion provided by the boilers would result in any measurable reductions of VOC. As noted above, the VOCs that remain in the exhaust stream from the reheat furnaces are likely to have a higher molecular weight and boiling point than could be controlled with the existing boilers.

(c) **Routing to a Flare**

The facility has four existing flares (three (3) Coke Oven Gas Flares and the Peachtree flare), which are currently used to control excess coke oven gas not otherwise combusted in the existing furnaces at the facility. Flaring is currently limited to periods when a major operation or source is inactive. Although it may be possible to route emissions from the HPH annealing furnaces to the flares, given the low concentration of VOC in the exhaust stream (less than 20 ppm), flaring is not anticipated to result in measurable VOC emissions reductions.

81 From proposed National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers. (75 FR 31907, June 4, 2010).
(d) **Carbon Adsorption**

Carbon adsorption is not considered technically feasible for HPH Annealing Furnaces. As discussed for the TO option, the concentration of VOC in the exhaust stream from the HPH Annealing furnaces is less than 20 ppm. In general, a carbon adsorber requires an inlet concentration stream of at least 1,000 ppm VOC to be effective. As such, the use of a carbon adsorber would not result in a measurable reduction of VOC. Additionally, carbon adsorbers generally require the exhaust gas temperature to be within a range of 100-200°F, which is significantly lower than the exhaust temperature of the annealing furnaces. Finally, if an adsorber were applied, the resulting pressure drop could result in additional costs if a larger fan were required. Therefore, the use of a carbon adsorber is considered not technically feasible for the annealing furnaces.

(e) **Condensers**

A condenser is not considered technically feasible for the HPH Annealing furnaces. As discussed for the TO option, the concentration of VOC in the exhaust stream from the HPH Annealing furnaces is less than 20 ppm. In general, a condenser requires an inlet concentration stream of at least 5,000 ppm VOC to be effective. As such, the use of a condenser would not result in a measurable reduction of VOC. Additionally, condensers generally require the exhaust gas temperature to be within a lower temperature range, usually requiring refrigeration to temperatures approaching -100°F. This is significantly lower than the exhaust temperature of the reheat furnaces; therefore a condenser could not be applied with significant, and likely costly, energy removal. Therefore, the use of a condenser is considered not technically feasible for the reheat furnaces.

(f) **Combustion/Performance Optimization**

Combustion optimization and operating and maintenance (O&M) practices are applicable to all types of furnaces combusting all types of fuels. Such practices are generally used throughout the industry to increase energy efficiency and lower fuel costs, as well as pollutant emissions. Currently, U.S. Steel – Irvin Plant is required to operate and maintain the HPH Annealing Furnaces in accordance with the good combustion and air pollution control practices, per RACT Order No. 258. Therefore, combustion/performance optimization practices are considered technically feasible for the HPH Annealing Furnaces, but no additional emission reductions would result because the source is already performing this activity.

**Step 3 - Evaluate Control Options**

**Emissions and Emission Reductions**

The HPH annealing furnaces are limited to 4.21 tons of VOC per year, for all furnaces combined. Although combustion/performance optimization practices are considered technically feasible for the HPH Annealing Furnaces, no additional emission reductions are expected.

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83 Id.
84 Id.
Economic Analysis

Because the source is currently performing combustion/performance optimization practices, no additional costs are anticipated.

Step 4 – Select RACT

The thirty-one (31) HPH Annealing Furnaces are already subject to the good combustion requirements of Article XXI; therefore, it was determined that RACT for these furnaces is no additional control, the existing limit on VOC emissions of 0.14 tpy per furnace, and compliance with Article XXI.

I. RACT for VOC – Coke oven gas flares [P015 - No.1 to No.3 and the Peachtree Flare]

Four (4) open candle stick flares used for combusting excess COG with a maximum design rate of 6.75 MMCF/day each. Flaring generally only occurs when a major operation or source (such as a blast furnace or the Hot Strip Mill) is not in service. Although the flares are open flares, Flares No. 1 through No. 3 are designated as exhausting to the same stack, SP20; the Peachtree Flare exhausts to stack SP21.

It should be noted that the Title V operating permit, condition V.K.1.d, states that VOC emissions from each subject flare shall not exceed 8.86 lbs per hour and 38.80 tons per year. [§2101.02.c.4 and §2105.21.h.4]

Step 1 – Identify Control Options

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the three (3) coke oven gas flares and the Peachtree Flare 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 Factors86, and a review EPA’s Standards of Performance for Petroleum Refineries87 to determine the available controls for flares.

Flares are often used to control VOC emissions through combustion. EPA performed flare studies as part of 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 VOC. In general, reductions of VOC 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. While good combustion practices do not result in specific VOC emissions reductions, properly operated flares are estimated to have at least 98% VOC destruction.88

(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.

FMP generally include 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.

FMPs do not result in specific VOC emissions reductions from a flare, but instead reduce the flow to the flare that generates VOC. However, because the VOC reductions depend on the source's ability to minimize the use of the flare, the emissions reductions cannot be predicted.

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**Step 2 – Eliminate Technically Infeasible Control Options**

Both of the control options identified are technically feasible for controlling VOC emissions from the three (3) coke oven gas flares and the Peachtree flare. This section presents the rationale explaining why each control option is technically feasible.

(a) Good engineering practices

Good engineering practices include the operation and maintenance of the flares in accordance with the flare design, including any manufacturer’s specifications and best practices. Such practices are recommended for optimal performance and are generally used throughout the industry. It is unclear how much operating using good engineering practices effects emissions from open flares. Therefore, this control measure is not evaluated further.

(b) Flare minimization plan

A flare minimization plan includes assessment and planning to reduce flare emissions by reducing the frequency and magnitude of flaring events. Flare

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management plans have been required of flares used at petroleum refineries, sulfur recovery plants, and hydrogen production plants, however, such plans could reasonably apply to the flares at the U.S. Steel – Irvin Plant.

The COG used at the facility is a byproduct obtained from coke ovens at U.S. Steel - Clairton Works and used downstream at the U.S. Steel – Edgar Thompson and U.S. Steel – Irvin Plant operations. The COG used at U.S. Steel – Irvin Plant must ultimately be flared for safety and to eliminate the small amount of hazardous air pollutants in the COG. U.S. Steel previously developed a system to reduce the amount of COG flared by converting the blast furnaces for all of its Mon Valley Works operations (Clairton Works, Edgar Thompson, and Irvin Plant) to utilize COG. The current system includes a COG processing facility at U.S. Steel – Clairton Works which processes the COG until its content is approximately 50-60 percent hydrogen. The COG is partially supplemented with natural gas to enrich certain properties that are needed to operate the various furnaces. The COG/natural gas mixture is subsequently piped to the U.S. Steel – Edgar Thomson and U.S. Steel – Irvin Plant operations, where it is used in reheat/annealing furnaces, and in collocated facilities.

The system devised by U.S. Steel Mon Valley Works displaces some of the natural gas previously used in the reheat/annealing furnaces at the Edgar Thompson and Irvin operations, and utilizes the COG produced at Clairton Works which would otherwise be flared. This system has resulted in significant reductions of the COG flared. When major manufacturing operations are normal, COG is completely utilized by the U.S. Steel Mon Valley Works operations. The flaring of COG is currently minimized to mainly times when a major operation or source are inactive. During scheduled maintenance outages, COG use is maximized at the other Mon Valley facilities.

Therefore, although a flare management plan is considered technically feasible for the three (3) coke oven gas flares and the Peachtree flare, U.S. Steel has previously evaluated and minimized the use of the flares. The system devised by U.S. Steel Mon Valley Works has also resulted in significant cost savings for the source. Therefore, the use of a flare minimization plan was not further considered for this source.

**Step 3 - Evaluate Control Options**

**Emissions and Emission Reductions**

The three (3) coke oven gas flares and the Peachtree flare have a potential to emit 38.8 tpy VOC each (or 155.2 tpy VOC for all flares) based on potential to emit calculations from the Title V Operating Permit #0050. The flares have a total design capacity of 27 million cubic feet per day or 6.75 mmcf/day per flare.

**Step 4 – Select RACT**

No additional controls are identified for the four coke oven gas flares. Because the flares are burning COG, the VOC emissions from these flares are relatively low (as compared to other fuels). As discussed in Step 3, U.S. Steel – Irvin Plant has evaluated and minimized the use of flaring at the facility. The system devised by U.S. Steel Mon Valley Works displaces some of the natural gas previously used in the reheat/annealing furnaces, and utilizes COG which would otherwise be flared. This system has resulted in significant reductions of the COG flared and limits flaring to mainly times when a major operation or source are inactive.
J. RACT for VOC – Solvent parts cleaning - cold cleaning [G002]

The solvent parts cleaning operation consists of cold cleaning degreasing machines that are self-contained and covered. The parts cleaners are used throughout the facility for cleaning and degreasing of rollers, bearings, steels parts, etc. The cleaners which are used are supplied by Safety Kleen. Emissions are uncontrolled and fugitive.

It should be noted that the Title V operating permit requires the solvent parts cleaning operations to meet the following requirements per §2105.15 and §2103.12.a.2.B:

- The permittee shall maintain all cleaning solvents containing volatile organic compounds in closed containers at all times except when in use.
- The permittee shall clean any spilled cleaning solvent that contains volatile organic compounds as expeditiously as possible.
- The emissions from parts solvent cleaning shall not exceed 30 tons/year of volatile organic compounds or 1.0 tons of hazardous air pollutants.
- The permittee shall not operate, or allow to be operated, any cold cleaning degreaser with a degreaser opening exceeding ten (10) square feet, unless:
  1) There is in operation on such degreaser:
     a) A cover to prevent evaporation of solvent during periods of non-use;
     b) Equipment for draining cleaned parts; and
     c) A permanent conspicuous label summarizing the operating requirements; and
  2) Such degreaser is operated at all times in such manner that:
     a) Waste solvents are transferred to another party or disposed of by means insuring that no more than 20% by weight of the solvents evaporate into the open air;
     b) Waste solvents are stored in covered containers;
     c) The degreaser cover is closed when parts are not being processed through the degreaser; and,
     d) Cleaned parts are drained for at least 15 seconds or until dripping ceases.

Step 1 – Identify Control Options

ACHD reviewed U.S. Steel – Irvin’s RACT submittal for the parts cleaning operations and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA’s CTG document for Volatile Organic Emissions from Stationary Sources and investigated additional resources to determine if any other VOC controls for reheat furnaces or other stationary external combustion sources have been demonstrated since the CTG document was published. The identified controls are discussed below.

The CTG document identifies the following control for cold-cleaner degreasers

(a) Use of Low-Volatility Solvents

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Use of a low-volatility solvent is not considered a VOC control technique, but more of a pollution prevention or source reduction technique. When considering the solvents used for degreasing, a solvent with a lower VOC content will result in fewer VOC emissions.

(b) Operating Practices

Good operating practices for degreasers generally include practices that ensure that exposure of the solvent to the atmosphere is minimized and evaporation is reduced. Generally, this includes keeping the solvent in closed containers except when in use, maintaining a cover on the degreaser and on waste solvents to prevent evaporation, maintaining draining facilities to allow the solvent to drip thoroughly from cleaned parts, and cleaning spilled solvents as quickly as possible.

The CTG document provided additional controls for open-top vapor and conveyerized degreasers (e.g., incinerators, adsorbers, absorption), however, these controls were not deemed appropriate for the cold cleaner degreasers at the Irvin plant.

Step 2 – Eliminate Technically Infeasible Control Options

This section presents the rationale explaining why each control option is, or is not, technically feasible.

(a) Use of Low-Volatility Solvents

The cleaners which are used by U.S. Steel – Irvin Plant are used based upon their premium solvent capabilities. The premium solvents must contain properties that reduce or eliminate any impacts from films, resins, or coatings that may remain on a part after cleaning, as well as corrosion issues associated with aqueous based cleaners. U.S. Steel – Irvin Plant reviewed solvents from a competitor (Quaker), but determined that the cleaners offered for the same capabilities are mineral solvent based, and would offer no emissions reductions. The use of a lower quality solvent could impact the quality of the products produced. Therefore, use of a lower-volatility solvent is considered technically infeasible.

(b) Operating Practices

U.S. Steel – Irvin Plant currently operates the solvent cleaning systems to meet the requirements of §2105.15, including operating all degreasers with container lids when not in use and other practices to reduce evaporation, and recycling all spent solvent. Therefore, no additional emissions reductions would be anticipated.

Step 3 - Evaluate Control Options

Emissions and Emission Reductions

Although operating practices are considered technically feasible for the solvent cleaning operations, the facility is already performing these activities, therefore, no additional emission reductions are expected.

Economic Analysis
Because the source is currently performing operating practices, no additional costs are anticipated.

**Step 4 – Select RACT**

The solvent parts cleaning operation is already subject to the requirements of Article XXI; therefore, it was determined that RACT for these operations is no additional control, the existing limit on VOC emissions of 30 tpy, and compliance with Article XXI.
April 4, 2014

Carl Dettlinger
Document Manager
Allegheny County Health Department
301 39th Street, Building #7
Pittsburgh, PA 15201

Re: U. S. Steel – Mon Valley Works – Irvin Plant
Title V Operating Permit – ACHD Permit #0050
Re-Evaluation of NOx and VOC Reasonably Available Control Technology

Dear Mr. Dettlinger:

In response to the request received from Sandra Etzel of the Allegheny County Health Department, U. S. Steel Corporation is hereby submitting a Re-Evaluation of NOx and VOC Reasonably Available Control Technology for its Mon Valley Works – Irvin Plant, Title V Operating Permit #0050.

If you have any questions, please contact me at (412) 675-7382 or email at alditullio@uss.com.

Sincerely,

Arica L. DiTullio, P. E.
Environmental Engineer
RE-EVALUATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY

Irvin Works
Dravosburg, Pennsylvania

RECEIVED

APR 07 2014

Prepared for:

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Dravosburg, Pennsylvania

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April 1, 2014

AMEC Project No. 3410140966
RE-EVALUATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY

Irvin Works
Dravosburg, Pennsylvania

April 1, 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 Engineer

Christopher M. Dunay
Senior Associate Scientist
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1.0 INTRODUCTION

U.S. Steel, Irvin Plant, in Dravosburg 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 a RACT analysis was required as part of the 1-hour ozone standard. 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. It is understood that the requirements in Section 2105.06 still apply, including the presumptive RACT requirements. RACT applies to major sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOCs). U.S. Steel Irvin is a major source for both NOx and VOCs.
2.0 FACILITY SOURCES

The Irvin plant is a secondary iron and steel processing facility that mainly molds, forms and refines steel slabs. As such, the facility does not melt or process raw materials for purposes of producing iron and steel, or their intermediates. Processing is mainly performed in cold and hot rolling mills, annealing, galvanizing and terne coating. Boilers are also operated at the facility for purposes of supplying process steam requirements.

Facility NOx and VOC sources consist of: reheat furnaces, annealing furnaces, galvanizing line furnaces and pots, process gas flares, steam boilers and space heaters. The Continuous Terne Line was idled in 2009 due to business conditions.

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 a presumptive RACT requirement contained in Section 2105.06, are included in a case-by-case RACT analysis. U.S. Steel Irvin source categories that are included in the analysis, based on this criteria, consist of:

- Five 80-inch Hot Strip Mill Reheat furnaces #1-5 (NOx and VOCs)
- Pre-Heat Furnace for the #1 Galvanizing Line process (NOx and VOCs)
- Coke Oven Gas Flares #1-4 and Peachtree COG Flare (VOCs)
- Boilers #1 and 2 (NOx and VOCs)
- Boilers #3 and 4 and Space Heaters (VOCs)

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:

- Space heaters (presumptive RACT, Section 2105.06.d, for NOx)
- Boilers #3 and #4 (presumptive RACT, Section 2105.06.d, for NOx)
- Coke Oven Gas Flares #1-4 (presumptive RACT, Section 2105.06.d, for NOx)
- HPH Batch, Continuous and Open Coil Annealing Furnaces #1-16 (presumptive RACT, Section 2105.06.d, for NOx)
- Lead Melt Pot
Provided in Tables 2.1 and 2.2 is a source-by-source listing of NOx and VOC emission sources at Irvin 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.

The 1993 and 2006 RACT analysis resulted in the following permit requirements, as part of the RACT Order #258:

- All combustion processes shall be operated in accordance with good engineering and air pollution control practices.

- The No. 3 five Strand Cold Rolling Mill and 80" Hot Strip Mill Rolling Stand with lubricating water emulsions must have a VOC content less than 7% and 4%, respectively, as well as an oil content of the rolling mill of 2%.

### 2.1 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 for NOx and VOCs respectively. 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 the 2012 AES*Online emission report. Note: all RACT analysis were 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. Several facilities covered in this study have operations similar to U.S. Steel Irvin 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:
<table>
<thead>
<tr>
<th>General NOx Control Technology Type(s)</th>
<th>Potential Control Efficiency (%)</th>
<th>Technical Concerning Technology Effectiveness</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low NOx Burners (LNB)</td>
<td>25-40</td>
<td>• Minimum temperature requirements</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Minimum oxygen levels</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Flame length</td>
</tr>
<tr>
<td>Flue Gas Recirculation (FGR)</td>
<td>30-50</td>
<td>• Minimum temperature requirements</td>
</tr>
<tr>
<td>or Overfire Air (OFA)</td>
<td></td>
<td>• Minimum oxygen levels</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Fan capacity</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Furnace pressure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Burner pressure drop</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Turndown stability</td>
</tr>
<tr>
<td>LNB + FGR or OFA</td>
<td>50-72</td>
<td>See LNB and FGR above</td>
</tr>
<tr>
<td>LNB + Selective Non-Catalytic Reduction (SNCR)</td>
<td>50-89</td>
<td>• High temperature requirements</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Ammonium sulfate formation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Ammonium water and wastes</td>
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<td></td>
<td></td>
<td>• Ammonia slip</td>
</tr>
<tr>
<td>Selective Non-Catalytic Reduction (SNCR)</td>
<td>20-45</td>
<td>See SNCR above</td>
</tr>
<tr>
<td>Ultra Low NOx Burners (ULNB)</td>
<td>75-85</td>
<td>See LNB above</td>
</tr>
<tr>
<td>Regenerative Selective Catalytic Reduction (RSCR)</td>
<td>50-70</td>
<td>• Only applied on large boilers at biomass plants</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Requires extensive new ductwork, heat exchangers and rerouting of gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Significant pressure drop increase</td>
</tr>
<tr>
<td>Selective Catalytic Reduction (SCR)</td>
<td>70-90</td>
<td>• Limited temperature range</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Ammonium sulfate formation/fouling</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Ammonia slip</td>
</tr>
</tbody>
</table>

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 RECR is not included in these literature reviews, it was added for completeness. RSRC 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 or furnace 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 direct flame slab heating furnace that could result in a lower NOx emission rate. However, the lower NOx burner application would negatively impact the slab quality (i.e., due to a change in temperature at the flame tip/slab interface), potentially developing an operation which would not consistently produce slabs within necessary specifications. In this case, the technology would be considered technically infeasible. Based on review of the referenced documents, literature available from vendors, engineering judgment and experience, the following NOx control options were identified as potentially technically feasible for the various source categories at U.S. Steel Irvin facility:

1) Hot Strip Mill Reheat Furnaces
   - LNB / ULNB – Yes
   - FGR or OFA – Yes
   - SNCR – No, see detailed source explanation.
   - RSCR – No, not proven on furnaces and rerouting ductwork would be too extensive. SCR – No, see detailed source explanation.

2) #1 Galvanizing Line Pre-Heat Furnace
   - LNB / ULNB – Yes
   - FGR or OFA – Yes
   - SNCR – Yes, with preheating of the exhaust gas.
   - RSCR – No, not proven on furnaces and rerouting ductwork would be too extensive.
   - SCR – Yes, with preheating of the exhaust gas.

3) Boilers #1 and #2
   - LNB / ULNB – Yes
   - FGR – Yes
   - OFA – Yes
   - SNCR – Yes
   - RSCR – No, boilers are of sufficient size but not demonstrated while firing alternative fuels such as COG or BFG. No vendor guarantees would be provided without extensive testing on alternative fuels.
   - SCR – Yes

3.2 OPERATIONAL CHANGES

The main operational changes for combustion related steel producing processes consist of fuel switching or reduction in combustion related excess air usage. Typically this consists of a switch from a solid or liquid fuel to a gaseous fuel. The Irvin facility has always operated the facility on
gaseous fuels. The primary fuel that is burned in the facility combustion sources is COG from the Clairton facility. Therefore, switching of fuels was not considered for further review, as the most effective fuel burning procedures are already being performed.

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 the boilers, steel making equipment (i.e., reheat and annealing furnaces) are direct fired sources and not typically amenable to substantive excess oxygen control. Reduction in excess air for these types of combustion sources is usually designed within the burner unit itself. Replacement burner units that operate at low excess air were considered in this study. Flare devices are also not equipped with air-to-fuel mixture controls. With the exception of some smaller ground level (fully enclosed) 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. 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 IRVIN

VOC emissions reviewed in this analysis are associated with by-products of fuel combustion. As such, efficient fuel combustion techniques produce low quantities of VOC emissions. However, for these sources potential VOC emissions reduction technologies, such as thermal oxidation, carbon adsorption, and condensations were reviewed, where applicable. If the concentration of VOC in the exhaust gas to be controlled is below the minimum VOC concentration that any control device is capable of effectively controlling, it was noted for that source, along with the concentration. 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.
4.0 SOURCE BY SOURCE EMISSION CONTROL REVIEW

4.1 80-INCH HOT STRIP MILL REHEAT FURNACES

Five identical reheat furnaces are used. The slab enters the furnace traveling vertically through the three heating zones. The Zone 1 (soak), zone 2 (top) and zone 3 (bottom) have 8, 6 and 6 burners, respectively. Temperatures within the furnace range from 1,800 – 2,400 °F. Metallurgy and slab quality are highly affected by the burner flame length, temperature and distribution; too much causing scaling, too little cause stress issues. U.S. Steel has been working with furnaces extensively, and have had studies performed to determine the operating conditions that are necessary to ensure the slab quality.

An SCR unit has been used on a slab furnace of this nature in the US; SNCR has not. LNB’s have also been installed in reheat furnaces, usually as part of a new furnace unit. Retrofit of some existing furnaces with LNB’s (including ultra low NOx burners [ULNB]) previously occurred as well, with mixed (product quality versus low NOx reduction) results, however, NOx emissions were generally reduced following installation. The SCR application did result in a reduction of emissions, however, was not successful from several standpoints; estimated emission reductions have never been achieved and reductions are not consistent, and the system degrades very quickly (frequent catalyst damage). Ammonia slip has also been a problem. The exhaust heat variations, flow rates, gas composition and oxygen content all contribute to issues with operation of an SCR on a reheat furnace. SNCR would also face the same major issues. For these reason, application of SCR and SNCR are still not considered to be technically feasible for reheat furnaces.

As a substantial change to the 2006 RACT analysis, more recent application of ULNB/LNB have been shown to be effective (to a degree) in reheat furnaces. In some applications retrofit LNB/ULNBs have been successful. Database searches indicate successful application of the burners. However, follow-up on some of those applications indicates that the emission reductions achieved were typically less than that listed in the database. Additionally, reheat furnaces reuse a portion of the exhaust stream for preheating, therefore, FGR is already performed in some manner. Some vendors indicate that additional FGR may be possible but would required detailed analysis and likely testing to assure no effect on product quality. The oxygen content provided in each zone of the furnace can have a significant effect of the product quality. Because of that, no vendor will provide guarantees or sound estimates of potential
reduction until they performed detailed studies, including pilot studies, on the specific furnace. Due to this fact FGR was not further considered. Due to the partial recirculation of exhaust gases already, likely, this is the reason that NOx emission rates are already generally lower than some other type furnaces. Additionally, U.S. Steel normally fires COG as the primary fuel, which as previously indicated, typically produces less NOx emission than natural gas. The control efficiently used for the cost analysis for theses furnaces is based upon the experience USS has gained from the installation of these same type burners on the same kind of reheat furnaces at the USS Granite City facility. Vendors generally indicated that they thought they could achieve lower NOx emissions than those achieved at Granite City, but could not confirm that. Vendors also indicated the same for the Granite City units, but could not achieve lower values (on a continuous and routine operation across all operational modes). So the lowest permitted limit that was achieved at Granite City was used as the basis for the emissions that could be achieved at Irvin. This emission rate is at the higher end of the range of emission limits noted in the database search for other reheat furnace applications, however, there is limited information on the levels that are being achieved in practice for the sources identified.

4.2 PRE-HEAT FURANCE FOR THE #1 GALVANIZING LINE

The melt pot pre-heat furnace for the #1 Line zinc galvanizing process is used to melt the coating materials before galvanizing. The melt pot furnace is of vertical movement design rated at 50 MMBTU/hr and provides a direct flame impingement on the strip from 240 burners throughout the furnace. Burners are installed within and through the furnace wall firebrick. On the reduction side of the furnace the system is operated fuel rich with cold air. Fuel is composed of natural gas. Exhaust gases are emitted at a temperature of 840-1000°F.

SCR and SNCR are both amenable to this operation. Exhaust gas would have to be preheated before treatment in a SNCR unit. A cost effectiveness analysis was performed for both technologies.

LN Bs and/or FGR or overfire air were considered to be technically feasible. Each burner would have to be replaced with a burner of similar design (i.e., flame speed, temperature length, heat output). Due to each burner’s size and length, vendors were not aware of replacement burners to match these specifications that operated in a low NOx mode.
4.3 BOILERS #1 AND #2

Four boilers supply steam to the facility, two are included in this review. Both boilers are watertube types fired with COG (primary) and natural gas on a swing load basis. Steam output for these boilers varies with facility demands, therefore, the load rates can swing from 10:1 rather quickly. Both boiler windbox and burner design produce NOx emissions comparable to rates typically offered for ULNB/LNB's plus FGR. LNBs were analyzed for cost effectiveness through direct vendor quotation. The quotation received indicates that a 25% reduction in NOx emissions is achievable compared to baseline potential boiler NOx emissions of 0.16 lbs/MMBTU.

SCR and SNCR are both amenable to NOx reduction for these operations. Exhaust gases would have to be preheated for both technologies, prior to treatment. SCR is expected to be capable of reducing NOx emissions by 80% or less. This lower expected efficiency is due to the low excess air in the exhaust of this operation (less than 5%). SCR units typically require at least 10% excess air to effectively reduce NOx to below 10% the reduction becomes unstable. SNCR reduction will be based by 45%, as indicated by the averages provided in Section 3.1. Each technology was analyzed for cost effectiveness.

The potential application of VOC controls was not further reviewed. The estimated concentration of VOC in the exhaust stream, based on potential emissions, is 30 ppb. This inlet concentration is below the minimum range of VOC that can be effectively controlled by VOC reduction control devices.
5.0 ECONOMIC FEASIBILITY

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 index 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 for SNCR. Results of the cost effectiveness analysis for each source are 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 Plan Approvals 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 Irvin Works. Technically feasible control options were identified for several sources. For these options, an economical feasibility (cost effectiveness) was performed. Based upon the results of both the technical and economic feasibility, no additional controls were considered to be both technically and economically feasible. Previous RACT requirements remain in-place. Based on this analysis, no additional control measures were considered to be RACT.
7.0 REFERENCES


UEC Environmental Systems, Inc., 1994, “Reasonably Available Control Technology Proposal for Emissions of NOx and VOCs from Sources at USS Mon Valley Works, Irvin Plant, Dravosburg, PA”.


U.S. Bureau of Labor and Statics, “Price Indices for Gross Domestic Product by Major Type of Product,” 2014

Bloom Engineering, Ultra Low NOx Burners for USS 80” HSM, February 21, 2014

Coen Division, John Zink Company, LLC, COG Retrofit Burner System for Boilers, March 11, 2014
<table>
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<tr>
<th>Source ID Number</th>
<th>Source Description</th>
<th>Process Rating</th>
<th>Year Installed</th>
<th>Buner Type/Method</th>
<th>Number of Burners</th>
<th>Firing</th>
<th>Fuels</th>
<th>POTENTIAL NOx CONTROL METHODS</th>
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<th>2012 Actual Emissions (ppm)</th>
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**Precautionary RACT applies:** RACT Order #298

**Presumptive RACT applies:** RACT Order #298
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<th>Indirect</th>
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<th>CO</th>
<th>SO2</th>
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<th>VOC Rate Limit (lb/MMBTU)</th>
<th>NACT Order #258 (tpy)</th>
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TABLE 5-1

U.S. Steel - Irvin
2014 RACT for 8-hour Ozone
NOx Controls Cost Effectiveness Summary Table

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<th>EMISSION SOURCES</th>
<th>80” Hot Strip Reheat Furnace</th>
<th>Galvanizing Pre-Heat Furnace (Melt Pot)</th>
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<th>Boiler #2</th>
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APPENDIX A

Summary of RACT/BACT/LAER Clearinghouse Database Review
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<th>Company</th>
<th>Facility Information</th>
<th>Pollutant</th>
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<th>Pollutant</th>
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<th>Other Information</th>
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<td>PISCO STEEL, INC</td>
<td>Modification of facility near Class 3 Area</td>
<td>Refuse Furnace</td>
<td>Natural gas fired, 400 m³/hr</td>
<td>NOx BACT PSD ≤ 1 lb/hr, 10 m³/day</td>
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<td>413-0033</td>
<td>5/10/2000</td>
<td>AL</td>
<td>AL-0128</td>
<td>National Steel Takeaway, Inc</td>
<td>New process addition and process modifications</td>
<td>Equilibration Furnace</td>
<td>Natural gas fired, 100 m³/day</td>
<td>NOx BACT PSD ≤ 1 lb/hr, 10 m³/day</td>
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<td>Thousand Oaks Steel and Stainless USA, LLC</td>
<td>New plant and stainless steel mill, rear of Class 3 area, to produce various grades and sizes of stainless steel in various forms</td>
<td>Arc Strip Mill</td>
<td>615 tons/hour, natural gas</td>
<td>NOx BACT PSD ≤ 1 lb/hr, 10 m³/day</td>
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<td>AR-0037</td>
<td>Steelcon, Inc.</td>
<td>Blast furnace, 20.000 m³/day</td>
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<td>Miscellaneous Furnaces, Furnace Heaters</td>
<td>206-0020-000</td>
<td>1/10/2006</td>
<td>AR</td>
<td>AR-0036</td>
<td>Steelcon, Inc.</td>
<td>New stainless steel furnace, for various purposes</td>
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<td>Natural gas, for auxiliary use</td>
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<td>North-Vestco Steel Corporation</td>
<td>New foundry furnace producing steel</td>
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<td>North Steel Arkansas</td>
<td>Scrap steel mill producing ferrous scrap for ship scrap and scrap</td>
<td>VTD Blower</td>
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<td>Secondary melt production of ferrous scrap (including steel scrap, cast iron, and scrap) using electric arc furnace, continuous casting, indirect steelmaking furnaces, and blast</td>
<td>VTD Blower</td>
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<td>P0H0690G</td>
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<td>O-0315</td>
<td>Hot Blast Furnace</td>
<td>The pellet reduced furnaces are using gas fired with a throughput of 5 to 6 MCF/hour.</td>
<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>1,594 lb/year</td>
<td>1,594 lb/year</td>
<td>91% bfmet</td>
<td>0.002 lb/MMBtu (secondary emissions)</td>
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<td>O-0519</td>
<td>Blast Furnace</td>
<td>The pellet reduced furnaces are using gas fired and rated at 300 MMBtu/hr (applied) at 150 MMBtu/hr (max).</td>
<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>296 lb/year</td>
<td>13.9 lb/year</td>
<td>30% BFMET</td>
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<td>O-0531</td>
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<td>Steel shop only CaF2, modification for substitution in some operations and installation of ladle-melting facility, rougher furnace, and fine dust control system.</td>
<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>1.1 lb/mmocx</td>
<td>13.5 lb/mmocx</td>
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<td>O-0519</td>
<td>Furnace</td>
<td>Furnace is 144 m tall and cylindrical.</td>
<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>778 lb/year</td>
<td>122 lb/year</td>
<td>5.2 lb/mmocx</td>
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<td>Natural gas, 139000 MMcf/year.</td>
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<td>3.5 lb/mmocx</td>
<td>3.5 lb/mmocx</td>
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<td>11/21/2009</td>
<td>PA</td>
<td>PA-0264</td>
<td>Hot Blast Furnace</td>
<td>Steel shop only CaF2, modification for substitution in some operations and installation of ladle-melting facility, rougher furnace, and fine dust control system.</td>
<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>1,440 lb/year</td>
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<td>Natural gas, 455 MMcf/year, each furnace fired with 10 to 15 MMBtu/hr and each furnace employs URH.</td>
<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>5.7 lb/mmocx</td>
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<td>0.003 lb/MMBtu (secondary emissions)</td>
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<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>5.7 lb/mmocx</td>
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<td>NOx-BACT-PID is Unregulated LHV Basis. VOC is not included in the listing.</td>
<td>5.7 lb/mmocx</td>
<td>5.7 lb/mmocx</td>
<td>5.7 lb/mmocx</td>
<td>0.003 lb/MMBtu (secondary emissions)</td>
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<td>Company</td>
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<td>Other Steel Manufacturing Processes</td>
<td>5430-0000-DO</td>
<td>5/3/2006</td>
<td>SC</td>
<td>SC-0112</td>
<td>Nucor Steel Bethlehem</td>
<td>Add new processes and modify processes located less than 100 km from a Class I area.</td>
<td>Vacuum Degasser Boiler</td>
<td>Natural gas fired, 10-21 mbtu/hr</td>
<td>NOx</td>
<td>0.039 bnn/hr</td>
<td>T1: 2.00 lb/hr</td>
<td>0.026 bnn/hr</td>
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<td>Natural Gas, includes propane and liquefied petroleum gas</td>
<td>5820-0001-DF</td>
<td>10/29/2006</td>
<td>SC</td>
<td>SC-0128</td>
<td>Nucor Steel Darlington</td>
<td>Bar product from steel scrap and scrap substitutes using an EAF</td>
<td>Refuse Furnace No. 2</td>
<td>Natural gas, 180 mbtu/hr</td>
<td>NOx</td>
<td>0.077 bnn/hr</td>
<td>T1: 0.0035 bnn/hr</td>
<td>The NOx emission limit will remain in effect until otherwise changed by the TAC of spark source civil No. 4-400945-26</td>
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<td>Miscellaneous Mill Shop Operations</td>
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<td>TX-0445</td>
<td>Structural Metals Inc.</td>
<td>Steel mini-mill</td>
<td>Refuse Furnace Stack</td>
<td>No further information</td>
<td>No control is noted for both NOx and VOC BACT-PSD</td>
<td>NOx</td>
<td>0.24 lb/hr</td>
<td>0.8 lb/hr</td>
<td>Notes associated with source in general - BACT control is the stack height</td>
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<td>Gasous Fuel &amp; Gasous Fuel Mixtures</td>
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<td>TX-0076</td>
<td>US Steel</td>
<td>New Greenfield facility that converts scrap steel into seamless pipe</td>
<td>Ruling Mill Furnaces</td>
<td>Natural gas fired, 428 mbtu/hr, includes rotary hearth furnaces (RHF), cold furnaces (CWF), should this be RRF? mandrel peel furnace (MPF), pipe mill furnace (PF), and tempering furnaces (TF), RHF: 142 mbtu/hr, MPF: 10-2 mbtu/hr, GF: 61 in mbtu/hr, TF: 51 mbtu/hr</td>
<td>NOx</td>
<td>0.185 bnn/hr</td>
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<td>US Steel</td>
<td>New Greenfield facility that converts scrap steel into seamless pipe</td>
<td>Vacuum Degasser Boiler</td>
<td>Natural gas, 40 mbtu/hr</td>
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<td>T1: 2.00 lb/hr</td>
<td>0.092 bnn/hr</td>
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APPENDIX B

U.S. Energy Information Administrator Reports

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APPENDIX C
Sample Cost Analysis Detail Sheet
**COMPANY:** U.S. Steel, Irvin, PA  
**Source:** Example  
**NOx Emission Control Option:** SNCR  
**Calculations based on Section 4.2 Chapter 1 of the EPA Air Pollution Control Cost Manual - Sixth Edition**

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<td>Electricity, $/kwh</td>
<td>i</td>
<td>NOX Removal Efficiency,η_{NOx} %\text{\textsubscript{ch}}</td>
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<td>Interest Rate, 1%</td>
<td>Operating Hours Per Year hrs/yr</td>
<td>Incremental Utility Requirements</td>
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<td>Water, $/1,000 gal</td>
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<td>Electricity, kw At cost</td>
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<td>BFG, $/MMBtu</td>
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<td>Water, 1,000 gal/hr At cost</td>
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<td>COG, $/MMBtu</td>
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<td>BFG, MMBtu/hr At cost</td>
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<td>NG, $/MMBtu</td>
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<td>COG, MMBtu/hr At cost</td>
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<td>Operating Labor, $/man-hr</td>
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<td>NG, MMBtu/hr At cost</td>
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<td>Included in DC</td>
<td>Reagent Volume, gallons Reagent solution flow rate, gal/hr x 24 hrs/day x 14 days/2 weeks x 52 weeks/yr</td>
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<td>Sales Tax, % of FOB</td>
<td>Included in DC</td>
<td>Reagent Cost, $/gallon At cost</td>
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<td>(a) Maintenance (Materials + Labor) % TC1</td>
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<td>(b) General Facilites, % DC</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>(c) Engineering and Home Office Fees % DC</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>(d) Process Contingency % DC</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>(e) Project Contingency % DC+IC</td>
<td>15%</td>
<td></td>
</tr>
<tr>
<td>(f) Preproduction Costs % of D+E</td>
<td>2%</td>
<td></td>
</tr>
</tbody>
</table>
COMPANY: U.S. Steel, Irvin, PA  
Source: Example  
NOx Emission Control Option: SNCR  
Calculations based on Section 4.2 Chapter 1 of the EPA Air Pollution Control Cost Manual - Sixth Edition

<table>
<thead>
<tr>
<th>TOTAL CAPITAL INVESTMENT</th>
<th>TOTAL ANNUAL COST</th>
<th>COST EFFECTIVENESS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TOTAL DIRECT CAPITAL COST</strong></td>
<td><strong>TOTAL ANNUAL COST</strong></td>
<td><strong>NOx removed, tpy</strong> = <strong>NOx_{in} x \eta_{NOx}</strong></td>
</tr>
<tr>
<td>$950/\text{MMBtu/hr}$</td>
<td><strong>Direct Annual Costs</strong></td>
<td><strong>Cost Efficiency</strong> = <strong>TAC / $/\text{MMBtu}</strong></td>
</tr>
<tr>
<td>$950/\text{MMBtu/hr}$</td>
<td><strong>Operating &amp; Supervisory Labor</strong> At Cost</td>
<td></td>
</tr>
<tr>
<td><strong>Auxiliary Equipment (Heat Exchanger)</strong></td>
<td><strong>Maintenance</strong> = <strong>TCI x a</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Total Indirect Capital Costs</strong></td>
<td><strong>Reagent Consumption</strong> = <strong>gal/hr x 3760 hr/yr x $/gal</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Indirect Installation, IC</strong> = <strong>DC x (b+c+d)</strong></td>
<td><strong>Utilities</strong> = <strong>$/kwh x $/kwh x hrs/yr</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Project Contingency, C</strong> = <strong>(DC+IC) x e</strong></td>
<td><strong>Water Consumption</strong> = <strong>1,000 gal/hr x $/1,000 gal x hrs/yr</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Total Plant Cost, D</strong> = <strong>DC + IC + C</strong></td>
<td><strong>Add'l Fuel Usage (Process related)</strong> = <strong>$/MMBtu x MMBtu/hr x hrs/yr</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Allowance for Funds During Constr., E</strong> = Assumed zero</td>
<td><strong>Auxiliary Equipment Requirements</strong> = <strong>$/MMBtu x MMBtu/scf flue gas x scf flue gas</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Royalty Allowance,F</strong> = Assumed zero</td>
<td><strong>Auxiliary Heating Costs</strong> = <strong>Net gas $/m3 x hrs/yr</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Preproduction Costs, G</strong> = <strong>(D + E + F) x f</strong></td>
<td><strong>cost required to heat boiler exhaust up</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Inventory Capital, H</strong> = <strong>Reagent vel, gal x $/gal</strong></td>
<td><strong>to SNCR required temperature</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Initial Catalyst and Chemicals, I</strong> = Assumed zero</td>
<td><strong>Total Direct Annual Costs</strong> = <strong>Sum all Direct Annual Costs</strong></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL CAPITAL INVESTMENT, TCI</strong> = <strong>(D+E+F+G+H+I)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>TOTAL ANNUAL COST, TAC</strong> = <strong>DAC + IDAC</strong></td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX D
Cost Analysis Detail Sheets
United States Steel
RACT Analysis for NOx - Irvin
Screening Calculation: Best Case NOX Removal with SCR, Flue Gas Heating Cost Only

Btu NOX/MMcf Natural Gas: 140

<table>
<thead>
<tr>
<th></th>
<th>Galv Heaer</th>
<th>BOILER #1</th>
<th>BOILER #2</th>
<th>80° Hot Strip</th>
<th>Furnace</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flue Gas</td>
<td>8.40E+08 scfm</td>
<td>20.500 scfm</td>
<td>21.812 scfm</td>
<td>5.99E+08 scfm</td>
<td></td>
</tr>
<tr>
<td>Flow</td>
<td>8.40E+08 scfh</td>
<td>1.26E+06 scfh</td>
<td>1.31E+06 scfh</td>
<td>5.99E+08 scfh</td>
<td></td>
</tr>
<tr>
<td>Temperature, °R (1)</td>
<td>650 °F</td>
<td>650 °F</td>
<td>650 °F</td>
<td>650 °F</td>
<td></td>
</tr>
<tr>
<td>Temperature, °R (2)</td>
<td>185 °F</td>
<td>185 °F</td>
<td>185 °F</td>
<td>185 °F</td>
<td></td>
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<tr>
<td>Heat Requirement</td>
<td>10.2 Lb/HR</td>
<td>10.2 Lb/HR</td>
<td>10.2 Lb/HR</td>
<td>10.2 Lb/HR</td>
<td></td>
</tr>
<tr>
<td>NOX Removed</td>
<td>2.86E-06 Lb/scf flue gas</td>
<td>8.26E-06 Lb/scf flue gas</td>
<td>8.27E-06 Lb/scf flue gas</td>
<td>6.71E-06 Lb/scf flue gas</td>
<td></td>
</tr>
<tr>
<td>NOX Rec'd</td>
<td>4.4 Btu/scf flue gas</td>
<td>4.4 Btu/scf flue gas</td>
<td>4.4 Btu/scf flue gas</td>
<td>4.7 Btu/scf flue gas</td>
<td></td>
</tr>
<tr>
<td>Natural Gas Cost (5)</td>
<td>$9.44 /MMBtu</td>
<td>$9.44 /MMBtu</td>
<td>$9.44 /MMBtu</td>
<td>$9.44 /MMBtu</td>
<td></td>
</tr>
<tr>
<td>Natural Gas Cost</td>
<td>-$12.26 /Lb NOX Removed</td>
<td>$5.45 /Lb NOX Removed</td>
<td>$5.04 /Lb NOX Removed</td>
<td>$6.55 /Lb NOX Removed</td>
<td></td>
</tr>
<tr>
<td>Natural Gas Cost</td>
<td>-$24.516</td>
<td>$10.904</td>
<td>$10.074</td>
<td>$13.091</td>
<td></td>
</tr>
<tr>
<td>Annual Natural Gas Cost (6)</td>
<td>-$314,971</td>
<td>$449,070</td>
<td>$477,811</td>
<td>$2,505,534</td>
<td></td>
</tr>
</tbody>
</table>

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 MMBtu natural gas.
(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

Hot Strip Furnace Max. Heat Input, \( Q_h = 140 \text{ MMBtu/hr} \)

System Capacity Factor, \( CF_{total} = CF_{plant} \times CF_{SCR} \)

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

\[
CF_{plant} = \frac{\text{Fuel Usage annual, lbs}}{\text{Fuel Usage potential, lbs}}
\]

\[
CF_{Hot} = \frac{\text{Actual 2013, MMBtu/hr}}{\text{Potential, MMBtu/hr}}
\]

\[
CF_{SCR} = \frac{t_{scr} \text{ (days / yr)}}{365 \text{ (days / yr)}}
\]

Uncontrolled NO\(_x\), Stack NO\(_x\) and NO\(_x\) Removal Efficiency

\[
\text{NOx}_{uni} \text{ (uncontrolled)} = 0.36 \text{ lb/MMBtu (Potential)}
\]

\[
\text{NOx Removal Efficiency, } \eta_{NOx} = 80\% \text{ lb/MMBtu (Stack Test)}
\]

Actual Stoichiometric Ratio, ASR

\[
\text{ASR} = \frac{\text{moles of equivalent NH}_2 \text{ injected}}{\text{mole of uncontrolled NO}_x}
\]

The value for ASR in a typical SCR system is approximately \( 1.05 \).

Normalized Stoichiometric Ratio, NSR

\[
\text{NSR} = \text{ASR} \times \text{SR}_1
\]

\[
\text{SR}_1 = 1 \text{ (Ratio of equivalent moles of NH}_3 \text{ per mole of reagent injected.)}
\]

\[
\text{NSR} = 1.05
\]
Free Gas Flow Rate, $q_{lmass}$

$$q_{lmass} = 96,850 \text{ acfm - based on average testing of furnaces.}$$

**Space Velocity and Area Velocity, $V_{space}$ & $V_{area}$**

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

$$V_{空间} = 0.02 \text{ ft}^3/\text{cfm}$$

$$V_{空间} = 4997 \text{ ft}^3$$

$$A_{area} = 0.005 \text{ ft}^2$$

$$A_{area} = 499.25 \text{ ft}^2$$

$$V_{area} = \frac{V_{space}}{A_{area}}$$

$$V_{area} = \frac{V_{space}}{200}$$

$$A_{specific} (\text{length/diameter}) = 0.25 \text{ ft}$$

**Catalyst Volume, $Vol_{catalyst}$**

pg 2-36 of SCR manual

$$Vol_{catalyst} = \frac{q_{mass} \times k \times \left( \frac{T_{max}}{45R} \right)}{k_{catalyst} \times A_{space}}$$

$$Vol_{catalyst} = 1997$$

**SCR Reactor Dimensions**

$$A_{catalyst} = 104.0 \text{ ft}^2$$

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

$$A_{sCR} = 119.6 \text{ ft}^2$$

$$L_{sCR} = 10.9 \text{ ft}$$

$$W_{sCR} = 10.9 \text{ ft}$$
\[ h_{\text{total}} = n_{\text{total}} \times \frac{L_{\text{inlet}}}{n_{\text{inlet}} \times A_{\text{inlet}}} \]

\[ h_{\text{total}} = n_{\text{total}} \times \frac{L_{\text{inlet}}}{n_{\text{inlet}} \times A_{\text{inlet}}} : 1 \]

\[ h_{\text{total}} = 4.1 \]

\[ n_{\text{total}} = n_{\text{inlet}} + n_{\text{empty}} \]

\[ n_{\text{empty}} = 3 \] (Assumption)

\[ n_{\text{total}} = 7.2 \] (This accounts for the fact that \( n_{\text{total}} \) does not include any empty catalyst layers for the future installation of catalyst).

\[ h_{\text{H2}} = n_{\text{total}} \times (c_1 + h_{\text{empty}}) + c_2 \]

\[ c_1 = 7 \] (Constants based on common industry practice)

\[ c_2 = 9 \]

\[ h_{\text{H2}} = 88.8 \]

**Estimating Reagent Consumption and Tank Size**

\[ m_{\text{reagent}} = \frac{NO_x \times Q_h \times NSR \times \eta_{\text{reagent}}}{M_{\text{NO}_x} \times SR_f} \]

- \( NO_x = 0.36 \) lb/MMBtu
- \( Q_h = 146 \) MMBtu/hr
- \( NSR = 1.05 \)
- \( \eta_{\text{reagent}} = 80\% \)
- \( M_{\text{reagent}} = 17.03 \) grams NH₃/mole
- \( M_{\text{NO}_x} = 46.01 \) grams NOx/mole
- \( SR_f = 1 \) (Ratio of equivalent moles of NH₃ per mole of reagent injected)

\[ m_{\text{reagent}} = 15.7 \] lbs/hr
For ammonia:

\[ m_{\text{act}} = \frac{m_{\text{reactant}}}{C_{\text{act}}} \]

\[ C_{\text{act}} = 29\% \] (Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)

\[ m_{\text{act}} = \frac{54.0}{\text{lbs/hr}} \]

\[ q_{\text{act}} = \frac{m_{\text{act}}}{\rho_{\text{act}} V_{\text{act}}} \]

\[ t_{\text{act}} = 56 \text{ lb/hr} \] (For a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)

\[ V_{\text{act}} = 7.481 \text{ gals/ft}^3 \] (Specific volume of a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)

\[ q_{\text{act}} = 7.2 \text{ gals/ft}^3 \]

Tank volume:

\[ V_{\text{tank}} = q_{\text{act}} \times t \]

\[ t = 14.0 \text{ days} \] (Common on site storage requirement, pg. 2-40 of SCR manual)

\[ V_{\text{tank}} = 2425 \text{ gallons} \]

**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 facilities, land and working capital.

Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. This includes costs of:

DC = associated with field measurements, numerical 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:

\[ DC = Q_a \cdot \left( \frac{3280}{MMBtu/hr} + f(h_{up}) + f(NH\text{rate}) + f(nic) + f(bypass) \right) \]

Where,

Adjustment for SCR reactor height:

\[ f(h_{up}) = \frac{6.12}{h_{up} \cdot MMBtu/hr} \cdot \frac{1}{MMBtu/hr} \] \[ f(h_{up}) = 356 \]

Adjustment for the ammonia flow rate:

\[ f(NH\text{rate}) = \frac{441}{m_{NH_3} \cdot Q_a} \cdot \frac{47.3}{MMBtu/hr} \]

\[ f(NH\text{rate}) = \$1.30 \]

For a retrofit:

\[ f(\text{new}) = \$  \quad \text{per MMBtu/hr} \]

For a new boiler:

\[ f(\text{new}) = \$ 1728 \quad \text{per MMBtu/hr} \]

Adjustment for installing an SCR bypass:

\[ f(\text{bypass}) = \$ \quad \text{per MMBtu/hr (if no bypass installed)} \]

\[ f(\text{bypass}) = \$ 427 \quad \text{per MMBtu/hr (if bypass installed)} \]

Capital cost for initial catalyzer charge

\[ f(Vol_{catalyst}) = Vol_{catalyst} \cdot CC_{catalyst} \]

\[ Vol_{catalyst} = \$ 1.967 \cdot 10^4 \quad \text{ft}^3 \]

\[ CC_{catalyst} = \$ 240 \quad \text{per ft}^3 \quad \text{(Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)} \]

\[ f(Vol_{catalyst}) = \$ 4792 \]

**Direct Capital, DC = $3,167,017** (Chemical Engineering Plant Index difference applied to DC. CFPCI in 1998 was 389.5; CFPCI 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.

\[
\text{Total Indirect Installation Costs, } IC = \frac{\$633,049}{1.15} = \text{DC} \times (\text{General Facilities } \% + \text{Engineering and Home Office Fees } \% + \text{Process Contingency } \%)
\]

- DC: (General Facilities \% + Engineering and Home Office Fees \% + Process Contingency \%)
  - General Facilities \% = 5\%
  - Engineering and Home Office Fees \% = 10\%
  - Process Contingency \% = 5\%

Project Contingency, C = $570,063 (15\% of DC + IC)

Total Plant Cost, D = $4,370,484.07 = DC + IC + C

Allowance for Funds During Construction, E = $ (Assumed zero for SCR)

Royalty Allowance, F = $ (Assumed zero for SCR)

Preproduction Costs, G = $87,409.68 (2.5\% of D + E)

Inventory Capital, H = $5,335,900 = \text{Vol}_{\text{invent}} \times \text{Cost}_{\text{invent}}$ (Mundi Index, Spot Market, January 2014)

\[
\text{Vol}_{\text{invent}} = 2,425 \text{ g} \text{g} \text{yr} \quad \text{Cost}_{\text{invent}} = 2.2 \text{ g} \text{g} \text{yr}
\]

Initial Catalyst and Chemicals, I = $ (Assumed zero for SCR)

Total Capital Investment, TCI = $4,463,229.66 = D + E + F + G + H

**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

\[ DAC = \left( \frac{Annual \text{ Maintenance Cost}}{Annual \text{ Reagent Cost}} \right) + \left( \frac{Annual \text{ Electricity Cost}}{Annual \text{ Water Cost}} \right) + \left( \frac{Annual \text{ Catalyst Cost}}{Annual \text{ Maintenance Cost}} \right) \]

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

**Maintenance:**

<table>
<thead>
<tr>
<th>Cost</th>
<th>Description</th>
<th>Calculation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$56,948</td>
<td>Total operating time, ( t_o ) = CF_{max} \times 8760 \text{ hrs/yr}</td>
<td>8760 hours</td>
<td>(CF not used as max hours required for RACT analysis)</td>
</tr>
</tbody>
</table>

**Reagent Consumption:**

<table>
<thead>
<tr>
<th>Cost</th>
<th>Description</th>
<th>Calculation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$22</td>
<td>Annual reagent cost</td>
<td>139,115 \times \text{con}_{\text{reagent}} \times t_o</td>
<td>\text{gallon}</td>
</tr>
</tbody>
</table>

**Utilities:**

\[ Power = 0.105 \left[ VO_{2max} \cdot \eta_{\text{elec}} \cdot 0.5(S_{\text{inlet}} - S_{\text{outlet}}) \right] \]

- \( \text{DF}_{\text{inlet}} = 2 \) inches water (Typical values as per pg. 2-46 of SCR manual)
- \( \text{DP}_{\text{catalyst}} = 0.75 \) inches water (Typical values as per pg. 2-46 of SCR manual)
- \( \text{Power} = 58.6 \) \text{kW} \text{h/kwh}
- \( \text{Cost}_{\text{elec}} = 0.07 \) $/kwh

<table>
<thead>
<tr>
<th>Cost</th>
<th>Description</th>
<th>Calculation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$35,926</td>
<td>Annual electricity cost = ( P \times \text{Cost}_{\text{elec}} \times t_o )</td>
<td>8760 hours</td>
<td></td>
</tr>
</tbody>
</table>

**Additional Energy Requirement = $10,904** (Additional heating of exhaust gas required for SCR operation.)
Catalyst Replacement:

Catalyst Replacement Cost = \( \text{R}_{\text{hr}} \times \text{Vol}_{\text{hr}} \times (\text{CC}_{\text{layer}} \times \text{R}_{\text{layer}}) \)

- \( \text{R}_{\text{hr}} = 1 \) for full replacement
- \( \text{R}_{\text{hr}} = 6.2 \) for replacing one layer per year
- \( \text{R}_{\text{layer}} = 1 \) (number of SCR reactors per boiler)

Catalyst Replacement Cost = $706,622.62

Annual Catalyst Replacement Cost = \((\text{Catalyst Replacement Cost}) \times (\text{FWF})\)

Future Worth Factor = \( \text{FWF} = \left( \frac{1}{(1 + i)^{T}} \right) \)

- Interest rate, \( i = 9.00\% \) (US Steel specific rate)
- \( T = \frac{b_{\text{motor}}}{b_{\text{hr}}} = 3 \) (hours operating life of catalyst as per pg 2.47 of SCR manual)
- \( b_{\text{motor}} = 24000 \) hours
- \( b_{\text{hr}} = 8760 \) hours
- \( \text{FWF} = 0.34 \)

Annual Catalyst Replacement Cost = $238,910

Total DAC = $491,803

Indirect Annual Costs, IDC:

Indirect Annual Cost, IDC = \( \text{CRF} \times \text{TAC} \)

CRF = Capital Recovery Factor,

\( \text{CRF} = \frac{(1 + i)^{T}}{(1 + i) - 1} \)

- Interest rate, \( i = 9.00\% \) (US Steel specific rate)
- Economic life of SNCR, \( m = 30 \) years
- CRF = 0.11

TCI - Total Capital Investment = $4,463,229.66

IDAC = $488,533

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC = $980,734.39

Total NO\(_x\) removed = 177 tpy
COMPANY: United States Steel  
LOCATION: Irvin  
Source: Hot Strip Reheat Furnace  
NOX Emission Control Option: SCR (80% Efficiency)

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Utility Unit Costs</strong></td>
<td><strong>Equipment Life, yr</strong></td>
<td><strong>Parrance Fuel Rating, mmBTU/hr</strong></td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td>0.07</td>
<td><strong>NOX Removal Efficiency, %</strong></td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td>9.00%</td>
<td><strong>Cost Year</strong></td>
</tr>
<tr>
<td>Operating Labor, $/man-hr</td>
<td>70.00</td>
<td><strong>Incremental Utility Requirement</strong></td>
</tr>
<tr>
<td>Manhours per year</td>
<td>547.5</td>
<td>Electricity, kw</td>
</tr>
<tr>
<td>Sales Tax, % of FOB</td>
<td>Included in DC</td>
<td>Reagent sol, gal/hr</td>
</tr>
<tr>
<td>Freight &amp; Ins. to Site, % of FOB</td>
<td>Included in DC</td>
<td>Catalyst operating hrs</td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI</td>
<td>1.5%</td>
<td><strong>General Facilities, % DC</strong></td>
</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Technologies (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAQPS cost Manual 5th Ed.

1 - USS specific rates for utilities, interest and labor.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Hot Strip Reheat Furnace  
**NOX Emission Control Option:** SCR (80% Efficiency)

### TOTAL CAPITAL INVESTMENT

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Direct Capital Cost, DC</td>
<td>$3,167,017</td>
</tr>
<tr>
<td>Auxiliary Equipment (Heat Exchanger)</td>
<td>$ -</td>
</tr>
<tr>
<td>Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales, tax and freight. Cost for heat exchanger not included.</td>
<td></td>
</tr>
<tr>
<td>Total Indirect Capital Costs:</td>
<td></td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td>$633,403</td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>$570,063</td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td>$4,370,484</td>
</tr>
<tr>
<td>Allowance for Funds During Constr., E</td>
<td>$ -</td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td>$ -</td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>$87,410</td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td>$5,336</td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td>$ -</td>
</tr>
<tr>
<td>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</td>
<td>$4,463,230</td>
</tr>
</tbody>
</table>

### TOTAL ANNUAL COST

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Annual Costs</td>
<td></td>
</tr>
<tr>
<td>Operating &amp; Supervisory Labor</td>
<td>$38,325</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$66,948</td>
</tr>
<tr>
<td>Reagent Consumption</td>
<td>$139,115</td>
</tr>
<tr>
<td>Utilities</td>
<td>$35,926</td>
</tr>
<tr>
<td>Catalyst Replacement</td>
<td>$238,940</td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements</td>
<td>$2,305,534</td>
</tr>
<tr>
<td>(Auxiliary Heating Costs = Nat'g gas cost required to heat boiler exhaust up to SNCR required temperature.)</td>
<td></td>
</tr>
<tr>
<td>Total Direct Annual Costs</td>
<td>$2,824,758</td>
</tr>
</tbody>
</table>

### INDIRECT ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRF</td>
<td>0.110</td>
</tr>
<tr>
<td>IDAC (CRF x TCI)</td>
<td>$488,931</td>
</tr>
<tr>
<td>TOTAL ANNUAL COST, TAC</td>
<td>$3,313,689</td>
</tr>
</tbody>
</table>

### COST EFFECTIVENESS

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx&lt;sub&gt;eq&lt;/sub&gt; lbs/ MMBtu</td>
<td>0.36</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>80%</td>
</tr>
<tr>
<td>Boiler Heat Input, MMBtu/hr</td>
<td>140</td>
</tr>
<tr>
<td>Total Operating Time, hrs/yr</td>
<td>8760</td>
</tr>
<tr>
<td>NOx removed, tpy</td>
<td>177</td>
</tr>
<tr>
<td>Cost Efficiency:</td>
<td></td>
</tr>
<tr>
<td>$/ton NOx removed</td>
<td>$18,764</td>
</tr>
</tbody>
</table>
SCR Design Parameters used for Estimation

Galvanizing Heater Max. Heat Input, \( Q_h \) = 50 MMBtu/hr

System Capacity Factor, \( CF_{total} = CF_{plant} \times CF_{SCR} \)
Capacity Factor, \( CF \), a measure of the average annual use of the boiler in conjunction with the SCR system.

\[
CF_{\text{plant}} = \frac{\text{Fuel Usage, annual, lbs}}{\text{Fuel Usage, potential, lbs}}
\]

\[
CF_{\text{Galv}} = \frac{\text{Actual, MMBtu/hr}}{\text{Potential, MMBtu/hr}}
\]

\[
CF_{\text{SCR}} = \frac{t_{\text{SCR}} \ (\text{days/yr})}{365 \ (\text{days/yr})}
\]

Uncontrolled NO\textsubscript{X}, Stack NO\textsubscript{X}, and NO\textsubscript{X} Removal Efficiency

\[
\text{NOX}_{\text{in, (uncontrolled)}} = 0.06 \text{ lb/MMBtu (Potential)}
\]

\[
\text{NOX Removal Efficiency, } \eta_{\text{NOX}} = 80\%
\]

\[
\text{Stack NOX} = 0.012 \text{ lb/MMBtu (Estimated)}
\]

Actual Stoichiometric Ratio, ASR

\[
\text{ASR} = \frac{\text{moles of equivalent NH}_2 \text{ injected}}{\text{mole of uncontrolled NO}_X}
\]

The value for ASR in a typical SCR system is approximately = 1.05

Normalized Stoichiometric Ratio, NSR

\[
\text{NSR} = \text{ASR} \times SR_1 \quad \text{(As per pg. 1-24 of Section Manual)}
\]

\[
SR_1 = 1 \quad \text{(Ratio of equivalent moles of NH}_2 \text{ per mole of reagent injected)}
\]

\[
\text{NSR} = 1.05
\]
Flue Gas Flow Rate, $q_{\text{fluegas}}$

$$q_{\text{fluegas}} = 14,000 \text{ acfm} \ - \text{ based on testing at Galv Pre-heat furnace}$$

Space Velocity and Area Velocity, $V_{\text{space}}$ & $V_{\text{area}}$

Vanadium (V205) Catalyst on honeycomb substrate with average pitch assumed

$$V_{\text{reactor}} = 0.02 \text{ ft}^3/\text{sec}$$
$$V_{\text{reactor}} = 280 \text{ ft}^3$$
$$A_{\text{area}} = 0.005 \text{ ft}^2/\text{sec}$$
$$A_{\text{reactor}} = 70 \text{ ft}^2$$

$$V_{\text{space}} = \frac{1}{\text{Residence Time}}$$

$$V_{\text{area}} = \frac{V_{\text{space}}}{A_{\text{specific area}} (\text{height/length})}$$

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

Catalyst Volume, $V_{\text{catalyst}}$

pg 2-36 of SCR manual

$$V_{\text{catalyst}} = \left[ \frac{q_{\text{fluegas}} \times \ln \left( 1 - \frac{V_{\text{reactor}}}{458} \right)}{K_{\text{catalyst}} \times A_{\text{catalyst}}} \right]$$

$$V_{\text{catalyst}} = V_{\text{reactor}} = 280$$

SCR Reactor Dimensions

$$A_{\text{reactor}} = \frac{q_{\text{fluegas}}}{V_{\text{reactor}} \times \text{ft} \times \text{sec} \times 60 \text{ sec/mm}}$$

$$A_{\text{catalyst}} = 14.6 \text{ ft}^2$$

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

$$A_{\text{catalyst}} = 46.8 \text{ ft}^2$$
$$t_{\text{cat}} = 4.1 \text{ ft}$$
$$w_{\text{scr}} = 4.1 \text{ ft}$$
\[ n_{\text{total}} = n_{\text{react}} \times n_{\text{empty}} \]

\[ h_{\text{react}} = \frac{V_{\text{react}}}{n_{\text{react}} \times A_{\text{react}}} \times 1 + h_{\text{empty}} \]

\[ h_{\text{react}} = 4.1 \] (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.)

\[ n_{\text{empty}} = 1 \] (Assumption)

\[ n_{\text{total}} = 7.193548387 \] (This accounts for the fact that \( n_{\text{react}} \) does not include any empty catalyst layers for the future installation of catalysts.)

\[ h_{\text{react}} = n_{\text{total}} (c_1 + h_{\text{empty}}) \times c_2 \] (Height of SCR reactor)

\[ c_1 = 7 \] (Constants based on common industry practice)

\[ c_2 = 9 \]

\[ h_{\text{react}} = 88.8483871 \]

Estimating Reagent Consumption and Tank Size

\[ m_{\text{reagent}} = \frac{NO_x \times Q_1 \times NSR \times n_{\text{react}} \times M_{\text{reagent}}}{M_{so_2} \times S_R_1} \]

\[ NO_x = 0.06 \quad \text{lb/MMBtu} \]

\[ Q_1 = 50 \quad \text{MMBtu/hr} \]

\[ NSR = 1.05 \]

\[ n_{\text{so}_2} = 80\% \]

\[ M_{\text{reagent}} = 17.03 \quad \text{grams NH}_3/\text{mole} \]

\[ M_{\text{so}_2} = 46.01 \quad \text{grams NO}_x/\text{mole} \]

\[ S_R_1 = 1 \] (Ratio of equivalent moles of NH\(_3\) per mole of reagent injected)

\[ m_{\text{reagent}} = 0.9 \quad \text{lbs/hr} \]
For ammonia,

\[ m_{\text{am}} = \frac{m_{\text{reactant}}}{C_{\text{am}}} \]

\[ C_{\text{am}} = 29\% \] *(Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)*

\[ m_{\text{am}} = 3.7 \text{ lb/hr} \]

\[ q_{\text{am}} = \frac{m_{\text{am}}}{\rho_{\text{am}} \cdot \gamma_{\text{am}}} \]

\[ r_{\text{am}} = 56 \text{ lb/hr} \] *(For a 29% solution ammonia at 60°F; pg. 2-40 of SCR manual)*

\[ v_{\text{am}} = 7.481 \text{ gal/hr} \] *(Specific volume of a 20% solution ammonia at 60°F; pg. 2-40 of SCR manual)*

\[ q_{\text{am}} = 0.4 \text{ gph} \]

Tank volume:

\[ V_{\text{tank}} = q_{\text{am}} \times t \]

\[ t = 14.0 \text{ days} \] *(Common on site storage requirement, pg. 2-40 of SCR manual)*

\[ V_{\text{tank}} = 144 \text{ gallons} \]

**TOTAL CAPITAL INVESTMENT, TC1**

* High-dust SCR system
* Ammoniacal ammonia used as the reagent
* Allowed ammonia slip range: 2-5 p.p.m.
* 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, site facilities, labor and working capital.

Direct Capital costs includes PEC such as SCR system equipment, instrumentation, safety and freight. This includes costs associated with field measurements, numerical 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:

\[
DC = Q_{3500} \left( \frac{\$3,380}{\text{MMBtu/hr}} + f_{\text{base}} + f_{\text{NH3 rate}} + f_{\text{new}} + f_{\text{bypass}} \right) + f(V\text{dilution})
\]

Where,

**Adjustment for SCR reactor height:**

\[
f_{\text{height}} = \left( \frac{\$6.12}{\text{ft} \cdot \text{MMBtu/hr}} \right) + \left( \frac{\$187.0}{\text{MMBtu/hr}} \right)
\]

**356**

**Adjustment for the ammonia flow rate:**

\[
f(\text{NH3 rate}) = \left( \frac{\$4.73}{\text{lb/hr}} \right) \left( \frac{\text{MMBtu/hr}}{Q_{3500}} \right)
\]

\[
f(\text{NH3 rate}) = (39.63)
\]

For a retrofit:

\[f(\text{new}) = \$ \quad \text{per MMBtu/hr}\]

For a new boiler:

\[f(\text{new}) = \$ \quad (728) \text{ per MMBtu/hr}\]

**Adjustment for installing an SCR bypass:**

\[f(\text{bypass}) = \$ \quad \text{per MMBtu/hr (if no bypass installed)}\]

\[f(\text{bypass}) = \$ \quad (127) \text{ per MMBtu/hr (if bypass installed)}\]

**Capital cost for initial catalyst charge:**

\[f(V_{\text{catalyst}}) = V_{\text{catalyst}} \times CC_{\text{catalyst}}\]

\[V_{\text{catalyst}} = \$ \quad 280.00 \quad \text{ft}^3\]

\[CC_{\text{catalyst}} = \$ \quad 240 \quad \text{per ft}^3 \quad \text{(Cost of initial catalyst: current estimation for a ceramic honeycomb catalyst)}\]

\[f(V_{\text{catalyst}}) = 6720\]

**Direct Capital, DC = \$ \quad 1,546,404** (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.

<table>
<thead>
<tr>
<th>Description</th>
<th>Calculation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Indirect Installation Costs, IC</td>
<td>$ = 269,281</td>
<td></td>
</tr>
<tr>
<td></td>
<td>+ DC x (General Facilities % + Engineering and Home Office Fees % + Process Contingency %)</td>
<td></td>
</tr>
<tr>
<td>General Facilities %</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Engineering and Home Office Fees %</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>Process Contingency %</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Project Contingency, IC -</td>
<td>$ = 242,353</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- 15% of DC + IC</td>
<td></td>
</tr>
<tr>
<td>Total Plant Cost, D</td>
<td>$ = 1,858,037.51</td>
<td></td>
</tr>
<tr>
<td></td>
<td>= DC + IC - C</td>
<td></td>
</tr>
<tr>
<td>Allowance for Funds During Construction, E</td>
<td>$ - (Assumed zero for SCR)</td>
<td></td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td>$ - (Assumed zero for SCR)</td>
<td></td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>$ = 37,160.75</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- 20% of D + E</td>
<td></td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td>$ = 317,61</td>
<td></td>
</tr>
<tr>
<td>Vol_regen</td>
<td>144 gal/yr</td>
<td></td>
</tr>
<tr>
<td>Cost_regen</td>
<td>2.2 $/gal</td>
<td></td>
</tr>
<tr>
<td>(Mundie Index, Spot Market, January 2014)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td>$ - (Assumed zero for SCR)</td>
<td></td>
</tr>
<tr>
<td>Total Capital Investment, TCI</td>
<td>$ = 1,895,515.87</td>
<td></td>
</tr>
<tr>
<td></td>
<td>= D + E + F + G + H + I</td>
<td></td>
</tr>
</tbody>
</table>

**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) marginal 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

\[
DAC = \left( \frac{\text{Annual Maintenance Cost}}{100} \right) + \left( \frac{\text{Annual Reagent Cost}}{100} \right) + \left( \frac{\text{Annual Electricity Cost}}{100} \right) + \left( \frac{\text{Annual Water Cost}}{100} \right) + \left( \frac{\text{Annual Catalyst Cost}}{100} \right)
\]

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

Maintenance:

<table>
<thead>
<tr>
<th>Total operating time</th>
<th>CT</th>
<th>x</th>
<th>8760 hr/yr</th>
<th>8760 hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance</td>
<td>$</td>
<td>28,434</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\[ t_p = \frac{CT_{total}}{CF} \times 8760 \text{ hr/yr} \]

Reagent Consumption:

\[ \text{cost}_{\text{reagent}} = 2.2 \text{ $/gallon} \]

\[ \text{Annual reagent cost} = 8,281 = \frac{Q_{\text{reagent}}}{\text{cost}_{\text{reagent}}} \times t_p \]

Utilities:

\[ \text{Power} = 0.1 \exp \left[ \frac{\text{NOX} \cdot \eta_{\text{elec}}}{0.4 \left( \eta_{\text{elec}} \cdot n_{\text{elec}} \cdot \Delta P_{\text{elec}} \right)} \right] \]

\[ \text{DP}_{\text{elec}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)} \]

\[ \text{HP}_{\text{elec}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)} \]

\[ \text{Power} = 19.7 \text{ $/kwh} \]

\[ \text{Cost}_{\text{elec}} = 0.07 \text{ $/kwh} \]

\[ t_p = 8760 \text{ hours} \]

Annual electricity cost:

\[ \text{Annual electricity cost} = P \times \text{Cost}_{\text{elec}} \times t_p = $ 12,658 \]

Additional Energy Requirement:

\[ \text{Additional energy required} = (24,516) \text{ (Additional heating of exhaust gas required for SCR operations.)} \]
Catalyst Replacement:

Catalyst Replacement Cost = \( n_{\text{scr}} \times V_{\text{catalyst}} \times (C_{\text{capital}}/R_{\text{tower}}) \)

\[
\begin{align*}
R_{\text{tower}} &= 1 \\
R_{\text{scr}} &= 6.2 \quad (\text{for replacing one layer per year}) \\
R_{\text{catalyst}} &= 1 \quad (\text{number of SCR reactors per boiler}) \\
C_{\text{capital}} &= $99,117.84 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574})
\end{align*}
\]

Annual Catalyst Replacement Cost = \( (C_{\text{capital}}/R_{\text{tower}}) \times (FWF) \)

Future Worth Factor = \( FWF = \frac{1}{(1+i)^t} \)

Interest rate, \( i = \) 9.00%  \( \quad \) US Steel Specific interest rate

Term, \( t = \) 3

\( k_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)} \)

\( h_{\text{catalyst}} = 1760 \quad \text{hours} \)

FWF = 0.34

Annual Catalyst Replacement Cost = $33,498

Total DAC = $57,753

Indirect Annual Costs, IDAC:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

\[ CRF = \frac{(1+i)^t}{1+(i)^t} \]

\( i = \) 9.00%  \( \quad \) US Steel Specific interest rate

Economic life of SCR, \( n = 20 \) years

CI = Total Capital Investment = $1,895,515.87

CRF = 0.11

IDAC = $207,647

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC = $265,400.34

Total NO\textsubscript{x} removed = 11 tpy
**COMPANY:** United States Steel  
**LOCATION:** Irvin  

*Source:* No. 1 Galvanizing Line Preheat Furnace  

**NOX Emission Control Option:** SCR (80% Efficiency)  

### Site Information
<table>
<thead>
<tr>
<th>Utility Unit Costs</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity, $/kwh</td>
<td>Equipment Life, yr 20.0</td>
<td>Heater Fuel Rating, mmBTU/hr 50</td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td>Operating Hours Per Year 8760</td>
<td>NOX Removal Efficiency, % 80</td>
</tr>
<tr>
<td>Operating Labor, $/man-hr 70.00</td>
<td></td>
<td>Cost Year 2014</td>
</tr>
<tr>
<td>Manhours per year 547.5</td>
<td></td>
<td>Incremental Utility Requirement</td>
</tr>
<tr>
<td>Sales Tax, % of FOB Included in DC</td>
<td>Reagent Sol, gal/hr 0.4</td>
<td>Catalyst operating life, hrs 24000</td>
</tr>
<tr>
<td>Freight &amp; Ins. to Site, % of FOB Included in DC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI 1.5%</td>
<td></td>
<td>General Facilities, % DC 5%</td>
</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Technologies (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAQPS cost Manual 5th Ed.  

1. USS specific rates for utilities, interest and labor.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** No. 1 Galvanizing Line Preheat Furnace  
**NOX Emission Control Option:** SCR (80% Efficiency)

### TOTAL CAPITAL INVESTMENT

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Direct Capital Cost, DC</td>
<td>$1,346,404</td>
</tr>
<tr>
<td>Auxiliary Equipment (Heat Exchanger)</td>
<td>$ -</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Indirect Capital Costs:</td>
<td></td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td>$269,281</td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>$242,335</td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td>$1,858,038</td>
</tr>
</tbody>
</table>

| Allowance for Funds During Constr., E            | $ -     |
| Royalty Allowance, F                            | $ -     |
| Preproduction Costs, G                          | $37,161 |
| Inventory Capital, H                            | $318    |
| Initial Catalyst and Chemicals, I               | $ -     |

**TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)** $1,895,516

### TOTAL ANNUAL COST

<table>
<thead>
<tr>
<th>Description</th>
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</tr>
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<tbody>
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<td>$38,325</td>
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<tr>
<td>Maintenance</td>
<td>$28,433</td>
</tr>
<tr>
<td>Reagent Consumption</td>
<td>$8,281</td>
</tr>
<tr>
<td>Utilities</td>
<td>$12,058</td>
</tr>
<tr>
<td>Catalyst Replacement</td>
<td>$33,498</td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements</td>
<td>$0</td>
</tr>
</tbody>
</table>

(Auxiliary Heating Costs = Nat'lgas cost required to heat boiler exhaust up to SCR required temperature)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Direct Annual Costs</td>
<td>$120,594</td>
</tr>
</tbody>
</table>

### INDIRECT ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRF</td>
<td>0.110</td>
</tr>
<tr>
<td>IDAC (CRF x TCI)</td>
<td>$207,647</td>
</tr>
</tbody>
</table>

**TOTAL ANNUAL COST, TAC** $328,241

### COST EFFECTIVENESS

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOX lb/ MMBtu</td>
<td>0.06</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>89%</td>
</tr>
<tr>
<td>Boiler Heat Input, MMBtu/hr</td>
<td>50</td>
</tr>
<tr>
<td>Total Operating Time, hrs/yr</td>
<td>8760</td>
</tr>
<tr>
<td>NOx removed, tpy</td>
<td>10.5</td>
</tr>
</tbody>
</table>

**Cost Efficiency:** $/ton NOx removed $31,225
SCR Design Parameters used for Estimation

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

System Capacity Factor, $CF_{total} = CF_{plant} \times CF_{SCR}$

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

$$CF_{plant} = \frac{\text{Fuel Usage}_{\text{annual, lbs}}}{\text{Fuel Usage}_{\text{potential, lbs}}}$$

$$CF_{Boiler\#1} = \frac{\text{Actual}_{\text{day}}, \text{MBtu/hr}}{\text{Potential, MBtu/hr}}$$

$CF_{Boiler\#1} = 0.45$

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

$t_{SCR} = 365 \ \text{days/yr}$

$CF_{in} = 1.00$

$CF_{out} = 0.45$

Uncontrolled NOx, Stack NOx, and NOx Removal Efficiency

$\text{NOx}_{\text{uncontrolled}} = 0.16 \ \text{lb/MMBtu (potential)}$

$\eta_{\text{NOx}} = 80\%$

$\text{Stack NOx} = 0.13 \ \text{lb/MMBtu (stack test)}$

Actual Stoichiometric Ratio, ASR

$$\text{ASR} = \frac{\text{moles of equivalent NH}_3 \text{ injected}}{\text{mol of uncontrolled NOx}}$$

The value for ASR in a typical SCR system is approximately $= 1.05$

Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR, \quad (As \ per \ pg. \ 1-24 \ of \ SCR \ manual)$$

$$SR = \frac{1}{1} \quad (\text{Ratio of equivalent moles of NH}_3 \text{ per mole of reagent injected})$$

$$NSR = 1.05$$
Flow Gas Flow Rate, \( q_{\text{flow}} \)

\[ q_{\text{flow}} = 37,156 \text{ acfm} \quad \text{based on testing at boilers.} \]

**Space Velocity and Area Velocity, \( V_{\text{space}} \) & \( V_{\text{area}} \)**

Vanadium (V205) Catalyst on honeycomb substrate with average pitch assumed.

\[
\begin{align*}
\text{Vol}_{\text{bed}} &= 0.02 \text{ ft}^3/\text{cfm} \\
\text{Vol}_{\text{reactor}} &= 743.12 \text{ ft}^3 \\
\text{Area}_{\text{bed}} &= 0.005 \text{ ft}^2/\text{cfm} \\
\text{Area}_{\text{reactor}} &= 185.78 \text{ ft}^2 \\
\frac{V_{\text{space}}}{\text{Residence Time}} &= 1 \\
\frac{q_{\text{flow}}}{\text{Vol}_{\text{reactor}}} &= 50 \\

\frac{V_{\text{area}}}{V_{\text{space}}} &= 200 \\

A_{\text{specific}} \quad \text{(specificed by catalyst manufacturer)} &= 0.25 \text{ ft} \\

\text{Catalyst Volume, Vol}_{\text{catalyst}} \quad \text{pg 2-36 of SCR manual} \\

\text{Vol}_{\text{reactor}} = \frac{q_{\text{flow}} \times 1 \text{ hr}}{16 \text{ ft}^3/\text{hr} \times 60 \text{ sec min}} \\
\text{Vol}_{\text{catalyst}} = 743.12 \\

\text{SCR Reactor Dimensions} \\

\text{A}_{\text{oil}} = \frac{q_{\text{flow}}}{16 \text{ ft}^3/\text{hr} \times 60 \text{ sec min}} \\
A_{\text{catalyst}} = 38.7 \text{ ft} \\
A_{\text{SCR}} = 1.15 \times A_{\text{catalyst}} \\
A_{\text{w}} = 44.5 \text{ ft}^2 \\
l_{\text{catalyst}} = 6.7 \text{ ft} \\
w_{\text{catalyst}} = 6.7 \text{ ft} \]
United States Steel  
RAC T Analysis for NOx - Irvin  
NOx Controls Cost Effectiveness Evaluation  
SCR Technology  
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.3 Chp. 1

\[
\eta_{\text{h meant}} = \frac{V \cdot \text{Max.} \cdot \text{Rating}}{\text{Outlet} \times 4 \cdot \text{Min.}}
\]

- \(\eta_{\text{h meant}} = 3.1\) ft (nominal height as per pg. 2-38 of SCR manual)
- \(\eta_{\text{h meant}} = 6.2\) ft (There must be at least two catalyst layers, pg. 2-38 of SCR manual)

\[
\tilde{h}_{\text{h meant}} = \left( \frac{V \cdot \text{Max.} \cdot \text{Rating}}{\eta_{\text{h meant}} \cdot \text{Rating}} \right) \times 1
\]

- \(\tilde{h}_{\text{h meant}} = 4.1\) 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)

\[
x_{\text{real}} = x_{\text{laye}} = x_{\text{empty}}
\]

- \(x_{\text{real}} = x_{\text{laye}} = 1\) (Assumption)
- \(x_{\text{real}} = 7.2\) (This accounts for the fact that \(n_{\text{empty}}\) does not include any empty catalyst layers for the furnace installation of catalyst).

\[
b_{\text{cuy}} = n_{\text{real}} \cdot (c_1 + b_{\text{meat}}) + c_2
\]

- \(b_{\text{cuy}} = 88.8\) (Height of SCR reactor)
- \(c_1 = 7\) (Constants based on common industry practice)
- \(c_2 = 9\)

**Estimating Reagent Consumption and Tank Size**

\[
m_{\text{reaction}} = \frac{NO_x \times Q_x \times NSR \times \eta_{\text{cuy}} \times M_{\text{reaction}}}{M_{\text{NO}_x} \times SR_f}
\]

- \(NO_x = 0.16\) lb/MMBtu
- \(Q_x = 79.8\) MMBtu/hr
- \(NSR = 1.05\)
- \(\eta_{\text{cuy}} = 80\%\)
- \(M_{\text{reaction}} = 17.03\) grams NH\(_3\)/mole
- \(M_{\text{NO}_x} = 46.01\) grams NO\(_x\)/mole
- \(SR_f = 1\) (Ratio of equivalent moles of NH\(_3\) per mole of reagent injected)
- \(m_{\text{reaction}} = 4.0\) lbs/hr
For ammonia,

\[ m_{\text{sol}} = \frac{m_{\text{reagent}}}{C_{\text{sol}}} \]

- \( C_{\text{sol}} = 29\% \) (Percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)
- \( m_{\text{sol}} = 13.7 \) lb/hr

\[ q_{\text{sol}} = \frac{n_l}{t_{\text{sol}} v_{\text{sol}}} \]

- \( t_{\text{sol}} = 56 \) lb ft\(^{-3}\) (For a 29% solution ammonia at 60°F, pg. 2-40 of SCR manual)
- \( v_{\text{sol}} = 7.481 \) gal ft\(^{-3}\) (Specific volume of a 20% solution ammonia at 60°F, pg. 2-40 of SCR manual)
- \( n_l = 1.8 \) gph

Tank volume:

\[ V_{\text{tank}} = q_{\text{sol}} x t \]

- \( t = 14.0 \) days (Common on site storage requirement, pg. 2-40 of SCR manual)
- \( V_{\text{tank}} = 614 \) 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 NO\textsubscript{X} 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 facilities, land and working capital.

Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. This includes costs

DOC = associated with field measurements, numerical 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:

\[
DC = Q_n \left( \frac{53.380}{MMBtu/hr} + f(Bypass) + f(NHRate) + f(NEW) + f(bypass) \right)
\]

Where,

Adjustment for SCR reactor height:

\[
f(h_{r, c}) = \frac{50.12}{\frac{ft \cdot MMBtu/hr}{hr}} \times \frac{Q_n}{MMBtu/hr}
\]

\[f(h_{r, c}) = 356\]

Adjustment for the ammonia flow rate:

\[
f(NHRate) = \frac{5411}{\frac{mole}{lb \cdot hr}} \times \frac{547.3}{MMBtu/hr}
\]

\[f(NHRate) = 20.85\]

For a retrofit:

\[f(NEW) = \text{per MMBtu/hr}\]

For a new boiler:

\[f(NEW) = 728 \text{ per MMBtu/hr}\]

Adjustment for installing an SCR bypass:

\[f(Bypass) = \text{per MMBtu/hr if no bypass installed}\]

\[f(Bypass) = 177 \text{ per MMBtu/hr if bypass installed}\]

Capital cost for initial catalyst charge:

\[
f(Vol_{catal}), = f(NEW) \cdot CC_{catal}
\]

\[Vol_{catal} = 743.12 \text{ ft}^3\]

\[CC_{catal} = 240 \text{ per ft}^3 \text{ (cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}\]

\[f(Vol_{catal}) = 17834.8\]

Direct Capital, DC = \$1,958,906 (Chemical Engineering Plant Index difference applied to DC: CEPCI in 1998 was 399.5; 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.

\[
\text{Total Indirect Installation Costs, } IC = \$391,781 \\
= DC \times (\text{General Facilities } \% + \text{Engineering and Home Office Fees } \% + \text{Process Contingency } \%)
\]

- General Facilities \% = 5\%
- Engineering and Home Office Fees \% = 10\%
- Process Contingency \% = 8\%

\[
\text{Project Contingency, } C = \frac{352603.0075}{\text{15\% of } DC + IC}
\]

\[
\text{Total Plant Cost, } D = \$2,703,289.72 = DC + IC + C
\]

- Allowance for Funds During Construction, $E = \$ - \text{(Assumed zero for SCR)}
- Royalty Allowance, $F = \$ - \text{(Assumed zero for SCR)}
- Preproduction Costs, $G = \$54,065.79 = \frac{2\%}{\text{of } D + E}

\[
\text{Inventory Capital, } H = \$1,351.76 = \text{Vol}_{\text{reqm}}(\text{gal}) \times \text{Cost}_{\text{reqm}}(\$/\text{gal})
\]

\[
\text{Vol}_{\text{reqm}} = 614 \text{ gal/yr}
\]

\[
\text{Cost}_{\text{reqm}} \approx 2.2 \$/\text{gal} \text{ (Mundi Index, Spot Market, January 2014)}
\]

- Initial Catalyst and Chemicals, $I = \$ - \text{(Assumed zero for SCR)}

\[
\text{Total Capital Investment, } TCI = \$2,758,707.28 = D + E + F + G + H + I
\]

**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.
Three Annual Costs, DAC

\[
DAC = \frac{\text{Annual Maintenance Cost}}{\text{Annual Reagent Cost}} + \frac{\text{Annual Electricity Cost}}{\text{Annual Water Cost}} + \frac{\text{Annual Catalyst Cost}}{\text{Annual Cost}}
\]

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 = $ 41,381

Total operating time, \( t_{op} = CF_{typ} \times 8760 \text{ hrs/yr} \)

  8760 hours (CF not used as max hours required for RACT analysis)

Reagent Consumption:

- Cost of Reagent: $ 2.2/gallon

  Annual reagent cost = $ 35,242 = q_{reagent} \times \text{Cost}_{reagent} \times t_{op}

Utilities:

\[
Power = 0.105 \left[ NO_x \cdot \eta_{st} \cdot 0.5 \left( AP_{inlet} \cdot \eta_{inlet} \right) \right]
\]

- \( DP_{inlet} = 2 \) inches water (Typical values as per pg. 2-46 of SCR manual)
- \( DP_{water} = 0.75 \) inches water (Typical values as per pg. 2-46 of SCR manual)
- Power = 32.1

Cost of Electricity = $ 0.07/kWh

\[
\text{Annual electricity cost} = P \times \text{Cost}_{elec} \times t_{op} = $ 15,656
\]

Additional Energy Requirement = $ 10,904 (Additional heating of exhaust gas required for SCR operations.)
**Catalyst Replacement**

Catalyst Replacement Cost = \( n_{\text{repl}} \times \text{Vol}_{\text{blank}} \times (C_{\text{rem}} \times R_{\text{rem}}) \)

- \( R_{\text{rem}} = 1 \) for full replacement
- \( n_{\text{repl}} = 6.2 \) (number of layers per year)
- \( \text{Vol}_{\text{blank}} = 1 \) (number of SCR reactors per unit)

Catalyst Replacement Cost = $263,058.76 (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 = \( FWF = \left(\frac{1}{(1 + i)^{T}}\right) \)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest rate, ( i )</td>
<td>9.00% US Steel specific rate</td>
</tr>
<tr>
<td>( T_{\text{term}} )</td>
<td>3 years</td>
</tr>
<tr>
<td>( h_{\text{catalyst}} )</td>
<td>24000 hours (operating life of catalyst as per pg 2.47 of SCR manual)</td>
</tr>
<tr>
<td>( h_{\text{oper}} )</td>
<td>8760 hours = ( t_{\text{y}} )</td>
</tr>
</tbody>
</table>

FWF = 0.34

Annual Catalyst Replacement Cost = $88,903

Total DAC = $196,085

**Indirect Annual Costs, DAC:**

Indirect Annual Cost, DAC = CRF x \( TCI \)

\( CRF = \text{Capital Recovery Factor} = \frac{r(1 + r)^T}{(1 + r)^T - 1} \)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest rate, ( i )</td>
<td>9.00% US Steel specific rate</td>
</tr>
<tr>
<td>Economic life of SCR, ( n_{\text{y}} )</td>
<td>20 years</td>
</tr>
<tr>
<td>CRF</td>
<td>0.110</td>
</tr>
</tbody>
</table>

\( TCI = \text{Total Capital Investment} = \$2,758,707.28 \)

IDAC = $302,207

**Total Annual Cost:**

Total Annual Cost, TAC = DAC + IDAC = $498,292.13

Total NO\(_x\) removed = 45 tpy
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #1  
**NOx Emission Control Option:** SCR (80% Efficiency)

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Utility Unit Costs</strong></td>
<td></td>
<td><strong>Boiler Fuel Rating, mmBtu/hr</strong> 80</td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td>Equipment Life, yr 20.0</td>
<td><strong>NOx Removal Efficiency, $/lbs NOx</strong> 80%</td>
</tr>
<tr>
<td>Interest Rate, % 9.00</td>
<td>Operating Hours Per Year 8760</td>
<td><strong>Cost Year</strong> 2014</td>
</tr>
<tr>
<td><strong>Operating Labor, $/man-hr</strong> 70.00</td>
<td><strong>Incremental Utility Requirement</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Manhours per year</strong> 547.5</td>
<td><strong>Electricity, kW</strong> 32</td>
<td></td>
</tr>
<tr>
<td><strong>Sales Tax, % of FOB</strong> Included in DC</td>
<td><strong>Reagent sol, gal/hr</strong> 1.8</td>
<td></td>
</tr>
<tr>
<td><strong>Freight &amp; Ins. to Site, % of FOB</strong> Included in DC</td>
<td><strong>Catalyst operating life, hrs</strong> 24000</td>
<td></td>
</tr>
<tr>
<td><strong>Maintenance (Material &amp; Labor) % TCI</strong> 1.5</td>
<td><strong>General Facilities, % DC</strong> 5%</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Engineering and Horse Office Fees % DC</strong> 15%</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Process Contingency % DC</strong> 5%</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Project Contingency % DC+IC</strong> 15%</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Preproduction Costs % of D+E</strong> 2%</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Reagent Volume, gallons</strong> 614</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Reagent Cost, $/gallon</strong> 2.20</td>
<td></td>
</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (IC) boilers." Section 6 for natural gas firing and OAQPS cost Manual 5th Ed.  
1 - USS specific rates for utilities, interest and labor.
### TOTAL CAPITAL INVESTMENT

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Direct Capital Cost, DC</td>
<td>$1,958,906</td>
</tr>
<tr>
<td>Auxiliary Equipment (Heat Exchanger)</td>
<td>$ -</td>
</tr>
<tr>
<td><strong>Direct Capital Costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.</strong></td>
<td></td>
</tr>
<tr>
<td>Total Indirect Capital Costs:</td>
<td></td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td>$391,781</td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>$352,603</td>
</tr>
<tr>
<td><strong>Total Plant Cost, D (DC + IC + C) $2,703,290</strong></td>
<td></td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td>$ -</td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>$54,066</td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td>$1,332</td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td>$ -</td>
</tr>
</tbody>
</table>

**TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I) $2,758,707**

### TOTAL ANNUAL COST

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Annual Costs</td>
<td></td>
</tr>
<tr>
<td>Operating &amp; Supervisory Labor</td>
<td>$38,325</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$41,381</td>
</tr>
<tr>
<td>Reagent Consumption</td>
<td>$35,242</td>
</tr>
<tr>
<td>Utilities</td>
<td>$19,656</td>
</tr>
<tr>
<td>Catalyst Replacement</td>
<td>$88,903</td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements (Auxiliary Heating Costs - Nat'1 gas cost required to heat boiler exhaust up to SCR required temperature)</td>
<td>$449,070</td>
</tr>
<tr>
<td><strong>Total Direct Annual Costs $672,577</strong></td>
<td></td>
</tr>
<tr>
<td>Indirect Annual Costs</td>
<td></td>
</tr>
<tr>
<td>CRF</td>
<td>0.110</td>
</tr>
<tr>
<td>IDAC (CRF x TCI)</td>
<td>$302,207</td>
</tr>
</tbody>
</table>

**TOTAL ANNUAL COST, TAC $974,784**

### COST EFFECTIVENESS

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOX emitted, lbs/MMBtu</td>
<td>0.16</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>80%</td>
</tr>
<tr>
<td>Boiler Heat Input, MMBtu/hr</td>
<td>79.8</td>
</tr>
<tr>
<td>Total Operating Time, hrs/yr</td>
<td>8760</td>
</tr>
<tr>
<td>NOX removed, tpy</td>
<td>44.7</td>
</tr>
</tbody>
</table>

**Cost Efficiency: $/ton NOX removed $21,788**
**SCR Design Parameters used for Estimation**

Boiler #2 Max. Heat Input, \( Q_6 \) = 84.6 MMBtu/hr

**System Capacity Factor, CF_{Total} = CF_{Plant} \times CF_{SCR}**

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

\[
CF = \frac{Actual_{\text{Fuel Usage, annual, lbs}}}{Potential_{\text{Fuel Usage, annual, lbs}}}
\]

\[
CF_{Boiler\ 2} = \frac{Actual_{2011\ MMBtu/hr}}{Potential_{43.33\ MMBtu/hr}}\ \text{(Boiler 2)}
\]

\[
CF_{SCR} = \frac{t_{SCR} \ (days/yr)}{365 \ (days/yr)} \times \frac{t_{wR}}{t_{wR}} \times \frac{CF_{wR}}{CF_{wR}} = \frac{365 \ days/yr}{365 \ days/yr} \times 1.00 \times 0.51
\]

**Uncontrolled NO\textsubscript{x}, Stock NO\textsubscript{x} and NO\textsubscript{x} Removal Efficiency**

\[
\text{NO}_x_{\text{(uncontrolled)}} = 0.16 \ \text{lb/MMBtu (Potential)}
\]

\[
\text{NOx Removal Efficiency, } \eta_{\text{SCR}} = 80\%
\]

\[
\text{Stock NO}_x = 0.13 \ \text{lb/MMBtu (Estimated)}
\]

**Actual Stoichiometric Ratio, ASR**

\[
\text{ASR} = \frac{\text{moles of equivalent NH}_3 \text{ injected}}{\text{mole of uncontrolled NO}_x}
\]

The value for ASR in a typical SCR system is approximately = 1.05

**Normalized Stoichiometric Ratio, NSR**

\[
\text{NSR} = \text{ASR} \times \text{SR}_{1} = \frac{1.05}{1.34 \ \text{(ratio of equivalent moles of NH}_3 \text{ per mole of reagent injected)}}
\]

\[
\text{SR} = t_{\text{SCR}} = 1.05
\]
**Fuel Gas Flow Rate, \( q_{\text{fuel}} \)**

\[
q_{\text{fuel}} = 39,530 \text{ acfm} \quad \text{based on testing at boilers.}
\]

**Space Velocity and Area Velocity, \( V_{\text{space}} \) & \( V_{\text{area}} \)**

Vanadium (V205) Catalyst on honeycomb substrate with average pitch assumed

\[
\begin{align*}
V_{\text{space}} &= 0.02 \text{ ft}^3/\text{cfm} \\
V_{\text{area}} &= 780.6 \text{ ft}^3 \\
A_{\text{specific}} &= 0.005 \text{ ft}^2/\text{cfm} \\
A_{\text{area}} &= 197.65 \text{ ft}^2
\end{align*}
\]

\[
\begin{align*}
\frac{1}{\text{Residence Time}} &= \frac{V_{\text{space}}}{V_{\text{area}}} \\
V_{\text{area}} &= \frac{V_{\text{space}}}{A_{\text{specific}}} \\
A_{\text{specific}} &= \frac{50}{200}
\end{align*}
\]

\[
A_{\text{specific}} = 0.25 \text{ ft}^2/\text{length} \times \text{length}
\]

**Catalyst Volume, \( V_{\text{catalyst}} \)**

pg 2-36 of SCR manual

\[
V_{\text{catalyst}} = \left( \frac{q_{\text{fuel}} \times \text{h}}{A_{\text{specific}} \times \frac{548}{\text{LPS}}} \right)
\]

\[
V_{\text{catalyst}} = 780.6 \text{ ft}^3
\]

**SCR Reactor Dimensions**

\[
A_{\text{catalyst}} = \frac{q_{\text{fuel}}}{16 \times 5.5 \times 60 \text{ sec/min}}
\]

\[
A_{\text{catalyst}} = 41.2 \text{ ft}^2
\]

\[
A_{\text{SCR}} = 1.15 \times A_{\text{catalyst}}
\]

\[
A_{\text{SCR}} = 47.4 \text{ ft}^2
\]

\[
L = 6.9 \text{ ft}
\]

\[
w = 6.9 \text{ ft}
\]
United States Steel  
RACE Analysis for NOx - Irvin  
NOx Controls Cost Effectiveness Evaluation  
SCR Technology  
Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

\[ h_{\text{top}} = \frac{V_{\text{cat, top}}}{A_{\text{sector}}} \]  
\[ n_{\text{top}} = 3.1 \text{ ft (nominal height as per pg. 2-38 of SCR manual)} \]  
\[ n_{\text{catalyst}} = 6.2 \quad \text{(There must be at least two catalyst layers, pg. 2-38 of SCR manual)} \]

\[ h_{\text{sec}} = \left( \frac{V_{\text{cat, sec}}}{n_{\text{catalyst}} \times A_{\text{sector}}} \right) + 1 \]

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

\[ n_{\text{total}} = n_{\text{sec}} + n_{\text{empty}} \]

\[ n_{\text{empty}} = 1 \quad \text{(Assumption)} \]

\[ n_{\text{catalyst}} = 7.2 \quad \text{(This accounts for the fact that } n_{\text{catalyst}} \text{ does not include any empty catalyst layers for the future installation of catalyst).} \]

\[ h_{\text{SCR}} = n_{\text{catalyst}} (c_1 + h_{\text{catalyst}}) + c_2 \]

\[ c_1 = 7 \quad \text{(Constants based on common industry practice)} \]

\[ c_2 = 0 \]

\[ h_{\text{ SCR}} = 88.8 \]

**Estimating Reagent Consumption and Tank Size**

\[ m_{\text{reagent}} = \frac{NO_x \times Q_x \times NSR \times \eta_{\text{NO}} \times M_{\text{reagent}}}{M_{\text{apps}} \times SR_f} \]

\[ NO_x = 8.36 \text{ lb/MMBtu} \]
\[ Q_x = 54.6 \text{ MMBtu/hr} \]
\[ NSR = 1.05 \]
\[ \eta_{\text{NO}} = 80\% \]
\[ M_{\text{reagent}} = 17.03 \text{ grams NH}_3/\text{mole} \]
\[ M_{\text{NO}_x} = 46.01 \text{ grams NO}_x/\text{mole} \]
\[ SR_f = 1 \quad \text{(Ratio of equivalent moles of NH}_3/\text{mole of reagent injected)} \]
\[ \sigma_{\text{reagent}} = 4.2 \text{ lb/hr} \]
For ammonia,

\[ m_{\text{sol}} = \frac{m_{\text{sol}}}{C_{\text{sol}}} \]

\[ C_{\text{sol}} = \frac{29}{100} \text{ (percent concentration of the aqueous reagent solution by weight, pg. 2-40 of SCR manual)} \]

\[ m_{\text{sol}} = 14.5 \text{ ft}^3 \text{ hr} \]

\[ q_{\text{sol}} = \frac{m_{\text{sol}}}{P_{\text{sol}} V_{\text{sol}}} \]

\[ t_{\text{sol}} = 56 \text{ lb/h} \] (For a 29\% solution ammonia at 60°F, pg. 2-40 of SCR manual)

\[ v_{\text{sol}} = 7.481 \text{ gal/h} \] (Specific volume of a 20\% solution ammonia at 60°F, pg. 2-40 of SCR manual)

\[ q_{\text{sol}} = 1.9 \text{ gal/h} \]

Tank volume:

\[ V_{\text{tank}} = q_{\text{sol}} \times t \]

\[ t = 14.6 \text{ days} \] (Common on site storage requirement, pg. 2-40 of SCR manual)

\[ V_{\text{tank}} = 651 \text{ gallons} \]

**TOTAL CAPITAL INVESTMENT, TCI**

Assumptions:
* High-dust SCR system
* Anhydrous ammonia used as the reagent
* Allowed ammonia sp. 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 facilitates, land and working capital.

Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. This includes costs

DC = associated with field measurements, numerical modeling and system design. It also includes direct installation costs such as auxiliary equipment (e.g. ductworks, compressors), 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:

\[ DC = Q_n \left[ \frac{53.380}{\text{MMBtu/hr}} + f(h_{byp}) + f(NH_{rate}) + f(new) + f(bypass) \right] \]

Where,

Adjustment for SCR reactor height:

\[ f(h_{byp}) = \frac{6.12}{h_{byp} \text{ ft} - \text{MMBtu/hr}} \times \frac{187.9}{\text{MMBtu/hr}} \]

\[ f(h_{byp}) = 356 \]

Adjustment for the ammonia flow rate:

\[ f(NH_{rate}) = \frac{41.1}{m_{NH3} \text{ lb/hr} - Q_n} \times \frac{187.9}{\text{MMBtu/hr}} \]

\[ f(NH_{rate}) = 388.5 \]

For a retrofit:

\[ f(new) = \$ \text{ per MMBtu/hr} \]

For a new boiler:

\[ f(new) = \$ (728) \text{ per MMBtu/hr} \]

Adjustment for installing an SCR bypass:

\[ f(bypass) = \$ \text{ per MMBtu/hr (if no bypass installed)} \]

\[ f(bypass) = \$ 127 \text{ per MMBtu/hr (if bypass installed)} \]

Capital cost for initial catalyst charge:

\[ f(Vol_{charge}) = \frac{Vol_{charge}}{CC_{initial}} \]

\[ Vol_{charge} = \$ 790.60 \text{ ft}^3 \]

\[ CC_{initial} = \$ 246 \text{ per ft}^3 \text{ Cost of initial catalyst/catalyst} \]

\[ f(Vol_{charge}) = 189744 \]

\[ \text{Direct Capital, DC} = \$ 2,041,337 \text{ (Chemical Engineering Plant Index difference applied to DC, CEPCI in 1998 was 389.5, CEPCI in 2013 was 574)} \]
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 TCL.

\[
\text{Total Indirect Installation Costs, IC} = D \times (\text{General Facilities}\% + \text{Engineering and Home Office Fees}\% + \text{Process Contingency}\%)
\]

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

Project Contingency, C = 367440.7055

\[
\text{Total Plant Cost, D} = 2,817,045.41 = DC + IC + C
\]

Allowance for Funds During Construction, E = $ - (Assumed zero for SCR)

Royalty Allowance, F = $ - (Assumed zero for SCR)

Preproduction Costs, G = $ 56,340.91

\[
\text{Inventory Capital, H} = 1,433.07 = \text{Vol}_{\text{nominal}} \times \text{Cost}_{\text{nominal}} / \text{gal}
\]

\[
\text{Vol}_{\text{nominal}} = 651 \text{ gal/yr}
\]

\[
\text{Cost}_{\text{nominal}} = 2.2 \text{$/gal} \quad \text{(Mandi Index, Spot Market, January 2014)}
\]

Initial Catalyst and Chemicals, I = $ - (Assumed zero for SCR)

\[
\text{Total Capital Investment, TC} = 2,874,819.39 = D + E + F + G + H + I
\]

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

\[
DAC = \left( \frac{\text{Annual Maintenance Cost}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent Cost}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity Cost}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water Cost}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst Cost}}{\text{Cost}} \right)
\]

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

Maintenance:

\[
\text{Maintenance} = \text{1.5\% of TCI}
\]

\[
\text{Total operating time, } t_{op} = CF \times 8760 \text{ hrs/yr} = 8760 \text{ hours (CF not used as max hours required for RACT analysis)}
\]

Reagent Consumption:

\[
\text{Cost}_{\text{reagent}} = \text{2.2 $/gallon}
\]

\[
\text{Annual reagent cost} = \text{Cost}_{\text{reagent}} \times t_{op} = 37,362
\]

Utilities:

\[
\text{Power} = 0.105 \left[ \text{NO}_x \times \eta_{\text{re}} \times 0.5 \left( \text{Power} - \eta_{\text{el}} \times 0.5 \right) \right]
\]

\[
\eta_{\text{re}} = 2 \quad \text{inches water (Typical values as per pg. 2-46 of SCR manual)}
\]

\[
\eta_{\text{el}} = 0.75 \quad \text{inches water (Typical values as per pg. 2-46 of SCR manual)}
\]

\[
\text{Power} = 34.0
\]

\[
\text{Cost}_{\text{elec}} = \text{0.07 $/kwh}
\]

\[
\text{Annual electricity cost} = \text{Cost}_{\text{elec}} \times t_{op} = 20,838
\]

Additional Energy Requirement = \text{10,074} (Additional heating of exhaust gas required for SCR operations.)
Catalyst Replacement:

\[ \text{Catalyst Replacement Cost} = n_{\text{SCR}} \times V_{\text{Catalyst}} \times (C_{\text{replace}} / R_{\text{mean}}) \]

\[ R_{\text{mean}} = \begin{cases} 1 & \text{for full replacement} \\ 6.2 & \text{for replacing one layer per year} \end{cases} \]

\[ n_{\text{SCR}} = \begin{cases} 1 & \text{number of SCR reactors per boiler} \end{cases} \]

\[ \text{Catalyst Replacement Cost} = \$ 279,866.31 \]

(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 \[ FWF = \frac{1}{(1 + i)^T} \]

\[ i = 9.00\% \quad \text{US Steel specific rate} \]

\[ T = \frac{h_{\text{catalyst}}}{h_{\text{mean}}} = 3 \]

\[ h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)} \]

\[ h_{\text{mean}} = 8760 \quad \text{hours = t} \]

\[ FWF = 0.34 \]

Annual Catalyst Replacement Cost = $94,583

Total DAC = $205,980

Indirect Annual Costs, IDAC:

Indirect Annual Cost, IDAC = CRF x TCI

\[ \text{CRF} = \frac{1}{(1 + i)^T} - 1 \]

\[ i = 9.00\% \quad \text{US Steel specific rate} \]

\[ T = \frac{\text{Economic life of SCR, in years}}{CRF} = 20 \]

TCI = Total Capital Investment = $2,874,839.36

IDAC = $314,926

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC = $528,906.09

Total NOx removed = 47.4 tpy
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #2  
**NOX Emission Control Option:** SCR (80% Efficiency)

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Unit Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.07</td>
<td></td>
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</tr>
<tr>
<td>Interest Rate, %</td>
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<td></td>
</tr>
<tr>
<td>9.00%</td>
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<tr>
<td>Operating Labor, $/man-hr</td>
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<tr>
<td>70.00</td>
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</tr>
<tr>
<td>Manouvres per year</td>
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<tr>
<td>547.5</td>
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<td></td>
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<tr>
<td>Sales Tax, % of FOB</td>
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</tr>
<tr>
<td>Included in DC</td>
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<td></td>
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<tr>
<td>Freight &amp; Ins. to Site, % of FOB</td>
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<td></td>
</tr>
<tr>
<td>Included in DC</td>
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<td></td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI</td>
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<td></td>
</tr>
<tr>
<td>1.5%</td>
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<tr>
<td>Equipment Life, yr</td>
<td>20.0</td>
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<tr>
<td>Operating Hours Per Year</td>
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<tr>
<td>Boiler Fuel Rating, mmBTU/hr</td>
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<td>85</td>
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<tr>
<td>NOX Removal Efficiency, %</td>
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<td>80%</td>
</tr>
<tr>
<td>Cost Year</td>
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<td>2014</td>
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<td>Incremental Utility Requirement</td>
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<tr>
<td>Electricity, kw</td>
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<td>34</td>
<td></td>
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<tr>
<td>Reagent sol. gal/hr</td>
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<tr>
<td>1.9</td>
<td></td>
<td></td>
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<tr>
<td>Catalyst operating life, hrs</td>
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<td></td>
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<tr>
<td>24000</td>
<td></td>
<td></td>
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<tr>
<td>General Facilities, % DC</td>
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<tr>
<td>5%</td>
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<td></td>
</tr>
<tr>
<td>Engineering and Home Office Fees % DC</td>
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<td></td>
</tr>
<tr>
<td>10%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Process Contingency % DC</td>
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<td></td>
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<tr>
<td>5%</td>
<td></td>
<td></td>
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<tr>
<td>Project Contingency % DC+IC</td>
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<td></td>
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<tr>
<td>15%</td>
<td></td>
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<tr>
<td>Preproduction Costs % of D+E</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2%</td>
<td></td>
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<tr>
<td>Reagent Volume, gallons</td>
<td></td>
<td></td>
</tr>
<tr>
<td>651</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reagent Cost, $/gallon</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.20</td>
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</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAQPS cost Manual 5th Ed.

1 - USS specific rates for utilities, interest and labor.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #2  
**NOx Emission Control Option:** SCR (80% Efficiency)

### TOTAL CAPITAL INVESTMENT

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Direct Capital Cost, DC</td>
<td>$2,041,337</td>
</tr>
<tr>
<td>Auxiliary Equipment (Heat Exchanger)</td>
<td>$-</td>
</tr>
<tr>
<td>Direct Capital costs includes PEC such as SCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.</td>
<td></td>
</tr>
<tr>
<td>Total Indirect Capital Costs:</td>
<td></td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td>$408,267</td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>$367,441</td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td>$2,817,045</td>
</tr>
<tr>
<td>Allowance for Funds During Constr., E</td>
<td>$-</td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td>$-</td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>$56,341</td>
</tr>
<tr>
<td>Inventory Capital, HI</td>
<td>$1,433</td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td>$-</td>
</tr>
<tr>
<td>**TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</td>
<td>$2,874,819</td>
</tr>
</tbody>
</table>

### TOTAL ANNUAL COST

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Annual Costs</td>
<td></td>
</tr>
<tr>
<td>Operating &amp; Supervisory Labor</td>
<td>$38,325</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$43,122</td>
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<tr>
<td>Reagent Consumption</td>
<td>$37,362</td>
</tr>
<tr>
<td>Utilities</td>
<td>$20,838</td>
</tr>
<tr>
<td>Catalyst Replacement</td>
<td>$94,533</td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements</td>
<td>$477,811</td>
</tr>
<tr>
<td>(Auxiliary Heating Costs = NatGas cost required to heat boiler exhaust up to SCR required temperature)</td>
<td></td>
</tr>
<tr>
<td><strong>Total Direct Annual Costs</strong></td>
<td>$712,042</td>
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<tr>
<td>Indirect Annual Costs</td>
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</tr>
<tr>
<td>CRF</td>
<td>0.110</td>
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<tr>
<td>IDAC (CRF x TCI)</td>
<td>$314,926</td>
</tr>
<tr>
<td><strong>TOTAL ANNUAL COST, TAC</strong></td>
<td>$1,026,968</td>
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### COST EFFECTIVENESS

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx Ea, lbs/MBtu</td>
<td>0.16</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>80%</td>
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<tr>
<td>Boiler Heat Input, MMbtu/hr</td>
<td>84.6</td>
</tr>
<tr>
<td>Total Operating Time, hrs/yr</td>
<td>8760</td>
</tr>
<tr>
<td>NOx removed, tpy</td>
<td>47.4</td>
</tr>
<tr>
<td>Cost Efficiency: $/ton NOx removed</td>
<td>$21,652</td>
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</tbody>
</table>
# Heat Capacity Boiler Combustion Stack Gas

<table>
<thead>
<tr>
<th></th>
<th>Galv Heater</th>
<th>BOILER #1</th>
<th>BOILER #2</th>
<th>SIF Hot Strip furnace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Flow (scfm)</td>
<td>Flow (scfh)</td>
<td>Flow (scfh)</td>
<td>Flow (scfh)</td>
</tr>
<tr>
<td></td>
<td>14,000</td>
<td>12,400</td>
<td>21,812</td>
<td>99,850</td>
</tr>
<tr>
<td></td>
<td>8,400</td>
<td>6,720</td>
<td>13,140</td>
<td>5,999,000</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>840 F</td>
<td>685 F</td>
<td>465 F</td>
<td>455 F</td>
</tr>
<tr>
<td></td>
<td>1650 F</td>
<td>1185 F</td>
<td>1195 F</td>
<td>1650 F</td>
</tr>
<tr>
<td>Heat Requirement</td>
<td>15.5 Btu/scf</td>
<td>22.6 Btu/scf</td>
<td>22.8 Btu/scf</td>
<td>22.8 Btu/scf</td>
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<tr>
<td>NOX Removed</td>
<td>93.0 ppmv</td>
<td>393.5 ppmv</td>
<td>419.5 ppmv</td>
<td>1558.8 ppmv</td>
</tr>
<tr>
<td>NOX control effy.</td>
<td>3.0 Lb/Hr</td>
<td>12.7 Lb/Hr</td>
<td>13.54 Lb/Hr</td>
<td>50.30 Lb/Hr</td>
</tr>
<tr>
<td>NOX Removed</td>
<td>45%</td>
<td>45%</td>
<td>45%</td>
<td>45%</td>
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<tr>
<td>NOX Removed</td>
<td>1.4 Lb/Hr</td>
<td>5.7 Lb/Hr</td>
<td>6.1 Lb/Hr</td>
<td>22.6 Lb/Hr</td>
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<tr>
<td>NOX Removed</td>
<td>1.66E-06 Lb/scf</td>
<td>4.65E-06 Lb/scf</td>
<td>4.65E-06 Lb/scf</td>
<td>3.78E-06 Lb/scf</td>
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<tr>
<td>NOX from Natural Gas Combustion</td>
<td>2.71E-06 Lb/scf</td>
<td>3.96E-06 Lb/scf</td>
<td>0.00E-00 Lb/scf</td>
<td>0.00E-00 Lb/scf</td>
</tr>
<tr>
<td>Net NOX Reduction</td>
<td>-1.10E-06 Lb/scf</td>
<td>6.89E-06 Lb/scf</td>
<td>4.65E-06 Lb/scf</td>
<td>3.78E-06 Lb/scf</td>
</tr>
<tr>
<td>Natural Gas E/f</td>
<td>80.0%</td>
<td>80.0%</td>
<td>80.0%</td>
<td>80.0%</td>
</tr>
<tr>
<td>Natural Gas Reqd</td>
<td>19.3 Btu/scf</td>
<td>28.3 Btu/scf</td>
<td>28.3 Btu/scf</td>
<td>28.5 Btu/scf</td>
</tr>
<tr>
<td>Natural Gas Reqd</td>
<td>1.93E-05 MMbtu/scf</td>
<td>2.83E-05 MMbtu/scf</td>
<td>2.83E-05 MMbtu/scf</td>
<td>2.85E-05 MMbtu/scf</td>
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<tr>
<td>Natural Gas Cost</td>
<td>$9.44/MMbtu</td>
<td>$9.44/MMbtu</td>
<td>$9.44/MMbtu</td>
<td>$9.44/MMbtu</td>
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<tr>
<td>Natural Gas Cost</td>
<td>$316.02/Lb NOX Removed</td>
<td>$347.66/Lb NOX Removed</td>
<td>$37.95/Lb NOX Removed</td>
<td>$71.26/Lb NOX Removed</td>
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<tr>
<td>Natural Gas Cost</td>
<td>$3,322,041/Ton NOX Removed</td>
<td>$755,379/Ton NOX Removed</td>
<td>$114,716/Ton NOX Removed</td>
<td>$142,512/Ton NOX Removed</td>
</tr>
<tr>
<td>Annual Natural Gas Cost</td>
<td>$3,742,772</td>
<td>$3,060,572</td>
<td>$142,512</td>
<td></td>
</tr>
</tbody>
</table>

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 MMcf natural gas.
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

Hot Strip Furnace Max. Heat Input, $Q_h = 140$ MMBtu/hr

System Capacity Factor, $CF_{\text{total}} = CF_{\text{plant}} \times CF_{\text{SNCR}}$
Capacity Factor, $CF$, a measure of the average annual use of the boiler in conjunction with the SNCR system

\[
CF_{\text{plant}} = \frac{Fuel \text{Usage}_{\text{annual}, \text{lbs}}}{Fuel \text{Usage}_{\text{potential, lbs}}}
\]

\[
CF_{\text{heater}} = \frac{Actual_{\text{2013}, \text{MMBtu/hr}}}{Potential_{\text{, MMBtu/hr}}} \times \frac{CF_{\text{Furnace}}}{0.89}
\]

\[
CF_{\text{SNCR}} = \frac{t_{\text{SNCR}} (days / yr)}{365 (days / yr)} + \frac{CF_{\text{SNCR}}}{1.00}
\]

Uncontrolled NOx, Stack NOx and NOx Removal Efficiency

$NOX_{\text{stack}}$ (uncontrolled) = 0.36 lb/MMBtu (Potential)

$NOX_{\text{removal efficiency}}$, $\eta_{\text{SNCR}}$, 45%

Stack NOx = 0.198 lb/MMBtu (Estimated)

Normalized Stoichiometric Ratio, NSR

\[
NSR = \frac{\left( \frac{2 \text{mol Urea}}{\text{mol NOx}} \right) \times NOX_{\text{stack}} + 0.7 \times \eta_{\text{SNCR}}}{NOX_{\text{stack}}}
\]

NSR = 1.78
Estimating Reagent Consumption

Reagent Consumption Parameters:

- \( \rho_{\text{sol}} = 9.5 \) Density of aqueous reagent solution (lb/gal) (For a 50% urea solution, as per page 1-27 of SNCR Manual)
- \( M_{\text{reagent}} = 60.06 \) Molecular weight of reagent (grams/mol Urea)
- \( M_{\text{NO}_x} = 46.01 \) Molecular weight of NO (grams/mol NO)
- \( SR_f = 2 \) Ratio of equivalent moles of NH\(_3\) per mole of reagent (mols NH\(_3\)/mol Urea)
- \( C_{\text{sol}} = 0.5 \) Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

\[
\dot{m}_{\text{reagent}} = \frac{NO_x \times \dot{Q}_{\text{b}} \times \eta_{\text{bi}} \times NSR \times M_{\text{reagent}}}{M_{\text{NO}_x} \times SR_f}
\]

\( \dot{m}_{\text{reagent}} \approx 26.3 \) lbs/hr

Aqueous reagent solution mass flow rate:

\[
\dot{m}_{\text{sol}} = \frac{\dot{m}_{\text{reagent}}}{C_{\text{sol}}}
\]

\( \dot{m}_{\text{sol}} \approx 52.6 \) lbs/hr

Solution volume flow rate:

\[
q_{\text{sol}} = \frac{\dot{m}_{\text{sol}}}{\rho_{\text{sol}}}
\]

\( q_{\text{sol}} \approx 5.54 \) gph

Aqueous reagent solution storage:

\[V_{\text{tank}} = q_{\text{sol}} \times t_{\text{storage}}\]

\( t_{\text{storage}} = 14.00 \) days (Assumption from pg. 1-27 in SNCR manual)

\( V_{\text{tank}} = 1860.31 \) 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 facilities, land and working capital.
Direct Capital costs include PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numerical 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:

\[
DC = \frac{950}{MMBtu/hr} Q_u \left( \frac{MMBtu}{hr} \right) \left( \frac{2375}{MMBtu/hr} \right) \left( 0.66 + 0.85 \eta_{sc} \right)
\]

DC = $1,047,495.83 (Chemical Engineering Plant Index difference applied to DC; CEPIC in 1998 was 389.5; CEPIC in 2013 was 574)

Indirect Capital Costs:

Total Indirect Installation Costs, IC = $209,499

= 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 = $188,549.25 = 15% of DC + IC

Total Plant Cost, D = $1,445,544.25 = DC + IC + C
Allowance for Funds During Construction, $E = \$ - (Assumed zero for SNCR)

Royalty Allowance, $F = \$ - (Assumed zero for SNCR)

Preproduction Costs, $G = 28,910.89

- 2% of $D + $F

Inventory Capital, $H = 89,481.06 = \text{Vol}_{\text{reagent}}[\text{gal}] \times \text{Cost}_{\text{reagent}}[\text{$/gal}]$

\[
\begin{align*}
\text{Vol}_{\text{reagent}} &= 48368 \text{ gal/yr} \\
\text{Cost}_{\text{reagent}} &= 1.85 \text{ $/gal} \\
\end{align*}
\]

$H$ gallon (Material Price Index for January 2014, United States)

Initial Catalyst and Chemicals, $I = \$ - (Assumed zero for SNCR)

Total Capital Investment, $TCI = 1,563,936.20 = \$ D + \$ E + \$ F + \$ G + \$ H + \$ I$

TOTAL ANNUAL COSTS

\[
\text{TAC} = \text{Total Annual Cost}
\]

Direct Annual Costs

- Includes: direct costs, indirect costs, and recovery credits.

- 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 equipment.

- Semivariable include: operating and supervisory labor and maintenance.

\[
\text{DAC} = \left(\frac{\text{Annual Maintenance Cost}}{\text{Cost}}\right) + \left(\frac{\text{Annual Reagent Cost}}{\text{Cost}}\right) + \left(\frac{\text{Annual Electricity Cost}}{\text{Cost}}\right) + \left(\frac{\text{Annual Water Cost}}{\text{Cost}}\right) + \left(\frac{\text{Annual Fuel Cost}}{\text{Cost}}\right)
\]

Operating and Supervisory Labor

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

Maintenance:

\[
\text{Maintenance} = 1.5\% \text{ of } TCI = \$ 23,459
\]

Total operating time, $t_{op} = C_{\text{total}} \times 8760 \text{ hrs/yr} = 8760 \text{ hours}$ (C not used as max hours required for RACT analysis)
Reagent Consumption (Urea):

\[\text{cost}_{\text{reagent}} = 1.85 \text{ $/gallon (Mundy Price Index for January 2014, United States)}\]

Annual reagent cost = $ \quad 89,727 = q_{\text{tot}} \times \text{cost}_{\text{reagent}} \times t_{\text{up}}

Utilities:

Power Consumption, \( P \):

\[P = 0.47 \times \text{NOx}_{\text{u}} \times \text{NSR} \times Q_b \times \frac{1}{0.5} \]

\[\text{NOx}_{\text{u}, \text{uncontrolled}} = 0.36 \text{ lb/MMBtu} \]

\[\text{NSR (Normalized Stoichiometric Ratio)} = 1.775 \]

\[Q_b, \text{boiler heat input} = 140 \text{ MMBtu/hr} \]

\[P = 4 \text{ kw} \]

\[\text{Cost}_{\text{elec}} = 0.07 \text{ $/kWh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.eia.gov)} \]

\[t_{\text{up}} = 8760 \text{ hours} \]

Annual electricity cost = \( P \times \text{Cost}_{\text{elec}} \times t_{\text{up}} = \)

\[2,714 \text{ per kWh} \]

Water Consumption:

\[q_{\text{water}} = \frac{m_{\text{col}}}{\rho_{\text{water}} \times \left( C_{\text{inlet}} - C_{\text{outlet}} \right)} \]

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

\[q_{\text{water}} = \frac{4m_{\text{col}}}{\rho_{\text{water}}} \]

\[\rho_{\text{water}} = 8.345 \text{ lbs/gal} \]

\[q_{\text{water}} = 0.02519 \text{ 1,000 gallons/hour} \]

Annual water cost = \( q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{up}} = \)

\[8.37 \text{ $/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial User}} \]

\[\text{http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.shtml} \]
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 10% solution
- Heat of vaporization of water is 900 Btu/lb

\[
\Delta F_{\text{fuel}} \left( \frac{\text{MMBtu}}{\text{hr}} \right) = \frac{900 \left( \frac{\text{Btu}}{\text{lb}} \right)}{10^3} \times \frac{\text{Btu}}{\text{MMBtu}} \times m_{\text{urea}} \left( \frac{\text{lb}}{\text{hr}} \right) \times 9
\]

\[
\Delta F_{\text{fuel}} \left( \frac{\text{MMBtu}}{\text{hr}} \right) = 0.2128
\]

**Annual cost for additional fuel:**

Average annual fuel consumption (calculated from 2012 fuel use data):

<table>
<thead>
<tr>
<th></th>
<th>Coke oven gas</th>
<th>Natural gas</th>
<th>Total MMBtu/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>99</td>
<td>26</td>
<td>125.00</td>
</tr>
</tbody>
</table>

Percent usage:

- Coke oven gas: 0.79
- Natural gas: 0.21

**Additional fuel required:**

Natural gas: 0.21283 MMBtu/hr
Total cost associated with additional fuel usage:

<table>
<thead>
<tr>
<th>Natural gas cost</th>
<th>$9.44</th>
<th>$/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$17,599.71</td>
<td>$/yr</td>
</tr>
</tbody>
</table>

Total Natural gas: $17,599.71

Additional Energy Requirement = $2,876,478 (Additional heating of exhaust gas required for SNCR operations.)

Total DAC = $3,011,824.13

Indirect Annual Costs:

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

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

Interest rate, i = 9.09% (US Steel Specific Interest Rate)
Economic life of SNCR, n = 20 years
CRF = 0.11

TCI = Total Capital Investment = $1,563,936.20
IDAC = $171,323.70

Total Annual Cost:
Total Annual Cost, TAC = DAC + IDAC = $3,183,147.82

Total NOx removed = 99 tpy
COMPANY: United State Steel  
LOCATION: Irvin  
Source: 80" Hot Strip Mill Furnace  
NOx Emission Control Option: SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Unit Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td>20.0</td>
<td></td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water, $/1,000 gal</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NG, $/MMBtu</td>
<td>9.44</td>
<td></td>
</tr>
<tr>
<td>Operating Labor, $/man-hr</td>
<td>70.00</td>
<td></td>
</tr>
<tr>
<td>Manhours per year</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales Tax, % of FOB</td>
<td>547.5</td>
<td></td>
</tr>
<tr>
<td>Freight &amp; Ins. to Site, % of FOB</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI</td>
<td>1.5%</td>
<td></td>
</tr>
<tr>
<td>General Facilities, % DC</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Engineering and Home Office Fees % DC</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>Process Contingency % DC</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Project Contingency % DC-IC</td>
<td>15%</td>
<td></td>
</tr>
<tr>
<td>Preproduction Costs % of DC-E</td>
<td>2%</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Source Emission Information</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment Life, yr</td>
<td>20.0</td>
<td></td>
</tr>
<tr>
<td>Operating Hours Per Year</td>
<td>8760</td>
<td></td>
</tr>
<tr>
<td>Boiler Fuel Rating, mmBTU/hr</td>
<td>85</td>
<td></td>
</tr>
<tr>
<td>NOx Removal Efficiency, %</td>
<td>35%</td>
<td></td>
</tr>
<tr>
<td>Cost Year</td>
<td>2014</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Utility Requirements</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity, kw</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Reagent sol. gal/hr</td>
<td>5.54</td>
<td></td>
</tr>
<tr>
<td>Water, 1,000 gal/hr</td>
<td>0.03</td>
<td></td>
</tr>
<tr>
<td>NG, MMBtu/hr</td>
<td>0.09238</td>
<td></td>
</tr>
</tbody>
</table>

| Reagent Volume, gallons     | 48368                          |                                |
| Reagent Cost, $/galion       | 1.85                           |                                |

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (IC) boilers." Section 6 for natural gas firing and 0 AQSPS cost Manual 5th Ed.  
1 - USS specific rates for utilities, interest and labor.
COMPANY: United States Steel
LOCATION: Irvin
Source: 80" Hot Strip Mill Furnace
NOx Emission Control Option: SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th>TOTAL CAPITAL INVESTMENT</th>
<th>TOTAL ANNUAL COST</th>
<th>COST EFFECTIVENESS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Direct Capital Costs:</strong></td>
<td>Direct Annual Costs</td>
<td>NOx, lbs/MBtu</td>
</tr>
<tr>
<td>Total Direct Capital Cost, DC</td>
<td>Operating &amp; Supervisory Labor</td>
<td>NOX removed, tpy</td>
</tr>
<tr>
<td>Auxiliary Equipment (Heat Exchanger)</td>
<td>Maintenance</td>
<td>0.36</td>
</tr>
<tr>
<td>Direct Capital costs includes PEC such as SNCR system equipment, instrumentation,</td>
<td>Reagent Consumption</td>
<td>Efficiency, %</td>
</tr>
<tr>
<td>sales tax and freight. Cost for heat exchanger not included.</td>
<td>Utilities</td>
<td>Boiler Heat Input, MMBtu/hr</td>
</tr>
<tr>
<td></td>
<td>Water Consumption</td>
<td>Total Operating Time, hrs/yr</td>
</tr>
<tr>
<td></td>
<td>Addt. Fuel Usage (Process related)</td>
<td></td>
</tr>
<tr>
<td>Total Indirect Capital Costs</td>
<td>Auxiliary Equipment Requirements</td>
<td></td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>(Auxiliary heating Costs + NaCl gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td>cost required to heat boiler exhaust up</td>
<td></td>
</tr>
<tr>
<td></td>
<td>to SNCR required temperature.)</td>
<td></td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td>Total Direct Annual Costs</td>
<td>$14,302,455</td>
</tr>
<tr>
<td>Allowance for Funds During Constr., E</td>
<td>Indirect Annual Costs</td>
<td></td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td>CRI</td>
<td>$145,762</td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>0.110</td>
<td></td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td>total IDAC (CRI x TC1)</td>
<td></td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</td>
<td>$1,563,936</td>
</tr>
<tr>
<td></td>
<td>TOTAL ANNUAL COST, TAC (DAC + IDAC)</td>
<td>$14,423,778</td>
</tr>
</tbody>
</table>
SNCR Design Parameters used for Estimation

Galv Pre-Heat furnace Max. Heat Input. $Q_a = 50$ MMBtu/hr

**System Capacity Factor, $CF_{total} = CF_{plant} \times CF_{SNCR}$**

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

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

$$CF_{Galv} = \frac{Actual_{2013}, MMBtu/hr}{Potential, MMBtu/hr}$$

$Actual_{2012} = 41.4$ MMBtu/hr

$Potential = 50$ MMBtu/hr

$CF_{Galv} = 0.83$

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

$t_{SNCR} = 365$ days/yr

$CF_{SNCR} = 1.00$

$CF_{total} = 0.83$

Uncontrolled NOx, Stack NOx and NOx Removal Efficiency

$NOx_{in} \ (uncontrolled) = 0.06$ lb/MMBtu (Potential)

$NOx \ Removal \ Efficiency, \ \eta_{nr} = 45\%$

$Stack \ NOx = 0.033$ lb/MMBtu (Estimated)

Normalized Stoichiometric Ratio, NSR

$$NSR = \frac{\left[ \frac{2 \ molH_{2} \ mol}{molNOX} \times NOX_{in} + 0.7 \right] \times \eta_{nr}}{NOX_{in}}$$

$NSR = 6.15$
Estimating Reagent Consumption

Reagent Consumption Parameters:

\[ \rho_{sol} = 9.5 \] Density of aqueous reagent solution [lb/gal] (For a 50% urea solution, as per page 1-27 of SNCR Manual)

\[ M_{reagent} = 60.06 \] Molecular weight of reagent (grams/mol Urea)

\[ M_{NO}_2 = 46.01 \] Molecular weight of NO\(_2\) (grams/mol NO\(_2\))

\[ \text{SR}\_\text{f} = 2 \] 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:

\[ m_{reagent} = \frac{NO\_\text{f} \times Q \times \eta_{NO}_2 \times SR\_f}{M_{NO}_2 \times SR\_f} \]

\[ m_{reagent} = 5.4 \text{ lbs/hr} \]

Aqueous reagent solution mass flow rate:

\[ m_{sol} = \frac{m_{reagent}}{C_{sol}} \]

\[ m_{sol} = 10.8 \text{ lbs/hr} \]

Solution volume flow rate:

\[ q_{sol} = \frac{m_{sol}}{\rho_{sol}} \]

\[ q_{sol} = 1.14 \text{ gph} \]

Aqueous reagent solution storage:

\[ V_{tank} = q_{sol} \times t_{storage} \]

\[ t_{storage} = 14.00 \text{ days (Assumption from pg. 1-27 in SNCR manual)} \]

\[ V_{tank} = 383.67 \text{ gallons} \]
TOTAL CAPITAL INVESTMENT, TC1

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 facilities, land and working capital.

Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numerical 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:

\[
DC = \frac{950}{MMBtu/hr} Q_h \left( \frac{MMBtu}{hr} \right) \left( \frac{2375}{MMBtu/hr} \right) \left( \frac{0.66 + 0.85 \eta_{in}}{2} \right)
\]

DC = $677,648.46 (Chemical Engineering Plant Index difference applied to DC; CEPPI in 1998 was 389.5; CEPPI in 2013 was 574.5)

Indirect Capital Costs:

Total Indirect Installation Costs, IC = $135,530

= 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 = $121,976.72 = 15% of DC + IC

Total Plant Cost, D = $935,154.88 = DC + IC + C

Allowance for Funds During Construction, E = $ - (Assumed zero for SNCR)

Royalty Allowance, F = $ - (Assumed zero for SNCR)

Preproduction Costs, G = $18,703.10 = 2% of D + E
United States Steel - Irvin
RACT Analysis No. 1 Galvanizing Line Preheat Furnace
NOx Controls Cost Effectiveness Evaluation
SNCR Technology

Utilizing EPA Air Pollution Control Cost Manual, 6th Ed., Section 4.2 Chp. 1

\[
\text{Inventory Capital, } H = \$ 18,454.34 = \text{Vol}_{\text{kgag}}(\text{gal}) \times \text{Cost}_{\text{kgag}}(\text{\$/gal})
\]

\[
\begin{align*}
\text{Vol}_{\text{kgag}} &= 9975 \text{ gal/yr} \\
\text{Cost}_{\text{kgag}} &= 1.85 \text{ \$/gal} \times \text{\$gallon (Mandi Price Index for January 2014, United States)}
\end{align*}
\]

Initial Catalyst and Chemicals, I = $ - $ (assumed zero for SNCR)

Total Capital Investment, TCI = $ 972,312.32 = D + E + F + G + H + I

**TOTAL ANNUAL COSTS**

\[
\text{TAC} = \text{Total Annual Cost}
\]

\[\text{DAC} = \text{Direct Annual Costs} \]

Includes: direct costs, indirect costs, and recovery credits.

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.

\[
\text{DAC} = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Fuel}}{\text{Cost}} \right)
\]

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

Maintenance:

<table>
<thead>
<tr>
<th>Maintenance</th>
<th>1.5% of TCI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance</td>
<td>$ 14,585</td>
</tr>
</tbody>
</table>

Total operating time, \( t_{op} = CF_{total} \times 8760 \text{ hrs/yr} \)

\( 8760 \text{ hours} \) (CF not used as max hours required for RACT analysis)

Reagent Consumption (Urea):

\[
\begin{align*}
\text{cost}_{\text{kgag}} &= 1.85 \text{ \$/gallon (As per page 3-30 from SNCR manual: CPI ratio applied to reflect 2014 prices)} \\
\text{Annual reagent cost} &= \$ 18,505 = \text{\$ros} \times \text{cost}_{\text{kgag}} \times t_{op}
\end{align*}
\]
Utilities:
Power Consumption, \( P \):
\[
P = \frac{0.47 \times NOx_{in} \times NSR \times Q_{hp}}{9.5}
\]

\( NOx_{in} \) (uncontrolled) = 0.06 lb/MMBtu
\( NSR \) (Normalized Stoichiometric Ratio) = 6.15
\( Q_{hp} \), boiler heat input = 50 MMBtu/hr
\( P \) = 1 kw
\( Cost_{elec} \) = 0.07 $/kwh (average 2014 cost from US Energy Information Administration statistics for Pennsylvania, www.eia.gov)
\( t_{hp} \) = 8760 hours

Annual electricity cost = \( P \times Cost_{elec} \times t_{hp} \) = $560 per kWh

Water Consumption:
\[
q_{water} = \frac{m_{air}}{\rho_{water}} \left( \frac{C_{\text{moisture,in}}}{C_{\text{moisture,out}}} - 1 \right)
\]

For urea dilution from a 50% solution to a 10% solution \( q_{water} \) becomes:
\[
q_{water} = \frac{4m_{air}}{\rho_{water}}
\]
\( \rho_{water} \) = 8.345 lb/gal
\( q_{water} \) = 0.00519 1,000 gallons/hour

Annual water cost = \( q_{water} \times Cost_{water} \times t_{hp} \) = $380.89 (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial Users)
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 a 10% solution
- Heat of vaporization of water is 900 Btu/lb

\[
\Delta F_{el} \left( \frac{MMBtu}{hr} \right) = \frac{900}{10^3} \left( \frac{\text{Btu}}{\text{lb Btu}} \right) \times m_{\text{urea}} \left( \frac{\text{lb}}{\text{hr}} \right) \times 9
\]

\[
\Delta F_{el} \left( \frac{MMBtu}{hr} \right) = 0.0439
\]

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Use (MMBtu/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>41.40</td>
</tr>
<tr>
<td>Total</td>
<td>41.40</td>
</tr>
</tbody>
</table>

Percent usage:

Natural gas 1.00

Additional fuel required:

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>0.0439</td>
</tr>
</tbody>
</table>
Total cost associated with additional fuel usage:

Natural gas cost \( 9.44 \) \text{M/MBtu} \\
\$ 3,629.72 \text{yr}

Total Natural gas: \$ 3,629.72

Additional Energy Requirement = \$ 1,342.771 (Additional heating of exhaust gas required for SNCR operations.)

Total DAC = \$ 1,380,430.73

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,
\[
CRF = \frac{(1 + i)^{n}}{(1 + i)^{n} - 1}
\]

Interest rate, i = 9.00% (US Steel Specific: Interest Rate)

Economic life of SNCR, \( n = 20 \) years

CRF = \( 0.11 \)

TCI = Total Capital Investment = \$ 972,312.32

IDAC = \$ 106,513.39

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC = \$ 1,486,944.11

Total NO\textsubscript{x} removed = 6 \text{tpy}
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** No. 1 Galvanizing Line Preheat Furnace  
**NOx Emission Control Option:** SNCR (45% Efficiency)

### Site Information

<table>
<thead>
<tr>
<th>Utility Unit Costs</th>
</tr>
</thead>
</table>
| Electricity, $/kwh         | 0.07  
| Interest Rate, %           | 9.66%  
| 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 & Inc. 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 + E | 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, mbtu/hr | 50  
| NOx Removal Efficiency, %    | 45%  
| Cost Year                    | 2014  

### Incremental Utility Requirements

| Electricity, kw             | 1  
| Reagent sol, gal/hr         | 1.14  
| Water, 1,000 gal/hr         | 0.01  
| NG, MMBtu/hr                | 0.04  

### Reagent Volume, gallons 

9975 gallons

| Reagent Cost, $/gallon      | 1.85  

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAQPS cost Manual 5th Ed.  
1 - USS specific rates for utilities, interest and labor.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** No. 1 Galvanizing Line Preheat Furnace  
**NOX Emission Control Option:** SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th>TOTAL CAPITAL INVESTMENT</th>
<th>TOTAL ANNUAL COST</th>
<th>COST EFFECTIVENESS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Direct Capital Cost, DC</strong></td>
<td>$677,648</td>
<td><strong>Direct Annual Costs</strong></td>
</tr>
<tr>
<td><strong>Auxiliary Equipment (Heat Exchanger)</strong></td>
<td>$ -</td>
<td><strong>Operating &amp; Supervisory Labor</strong></td>
</tr>
<tr>
<td><strong>Total Indirect Capital Costs:</strong></td>
<td></td>
<td><strong>Maintenance</strong></td>
</tr>
<tr>
<td><strong>Indirect Capital, IC</strong></td>
<td>$135,530</td>
<td><strong>Reagent Consumption</strong></td>
</tr>
<tr>
<td><strong>Project Contingency, C</strong></td>
<td>$121,977</td>
<td><strong>Utilities</strong></td>
</tr>
<tr>
<td><strong>Total Plant Cost, D (DC + IC + C)</strong></td>
<td>$935,355</td>
<td><strong>Water Consumption</strong></td>
</tr>
<tr>
<td><strong>Allowance for Funds During Constr, E</strong></td>
<td>$ -</td>
<td><strong>Add'l Fuel Usage (Process related)</strong></td>
</tr>
<tr>
<td><strong>Royalty Allowance, F</strong></td>
<td>$ -</td>
<td><strong>Auxiliary Equipment Requirements</strong></td>
</tr>
<tr>
<td><strong>Preproduction Costs, G</strong></td>
<td>$18,703</td>
<td><strong>(Auxiliary Heating Costs + Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature)</strong></td>
</tr>
<tr>
<td><strong>Inventory Capital, H</strong></td>
<td>$18,454</td>
<td><strong>Total Direct Annual Costs</strong></td>
</tr>
<tr>
<td><strong>Initial Catalyst and Chemicals, I</strong></td>
<td>$ -</td>
<td><strong>Indirect Annual Costs</strong></td>
</tr>
<tr>
<td><strong>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</strong></td>
<td>$972,312</td>
<td><strong>CRF</strong></td>
</tr>
<tr>
<td><strong>TOTAL ANNUAL COST, TAC (DC + IDAC)</strong></td>
<td>$1,526,260</td>
<td><strong>Total IDAC (CRF x TCI)</strong></td>
</tr>
<tr>
<td><strong>COST EFFECTIVENESS</strong></td>
<td></td>
<td><strong>NOX, lbs/MMBtu</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Efficiency, %</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Heater Heat Input, MMBtu/hr</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Operating Time, hrs/yr</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>NOX removed, tpy</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Cost Efficiency:</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>$/ton NOX removed</strong></td>
</tr>
</tbody>
</table>
SNCR Design Parameters used for Estimation

Boiler #1 Max. Heat Input, \( Q_b = 79.8 \) MMBtu/hr

System Capacity Factor, \( CF_{\text{total}} = CF_{\text{fuel}} \times CF_{\text{SNCR}} \)
Capacity Factor, \( CF \), a measure of the average annual use of the boiler in conjunction with the SNCR system.

\[
CF_{\text{fuel}} = \frac{\text{Fuel Usage \_annual \_lbs}}{\text{Fuel Usage \_potential \_lbs}}
\]

\[
CF_{\text{Boiler \#1}} = \frac{\text{Actual\_2013, MMBtu/hr}}{\text{Potential, MMBtu/hr}} = \frac{36 \text{ MMBtu/hr}}{79.8 \text{ MMBtu/hr}} = 0.45
\]

\[
CF_{\text{SNCR}} = \frac{t_{\text{SNCR \_days \_yr}}}{365 \text{ (days \_yr)}} = \frac{365 \text{ days/yr}}{365 \text{ (days \_yr)}} = 1.00
\]

\[
CF_{\text{total}} = 0.45
\]

Uncontrolled NO\(_x\), Stack NO\(_x\) and NO\(_x\) Removal Efficiency

\[
\text{NO\(_x\)_st (uncontrolled)} = 0.16 \text{ lb/MMBtu (Potential)}
\]

\[
\eta_{\text{SNCR}} = 95\% \text{ NO\(_x\) Removal Efficiency}
\]

Stack NO\(_x\) = 0.13 lb/MMBtu (Stack Test)

Normalized Stoichiometric Ratio, NSR

\[
NSR = \left[ \frac{2 \text{mol} / \text{req}}{\text{molNO\(_x\)}} \times \text{NO\(_x\) in, \_lb} + 0.7 \right] \times \eta_{\text{SNCR}}
\]

\[
NSR = 2.87
\]
Estimating Reagent Consumption

Reagent Consumption Parameters:

\[ p_{\text{sol}} = 9.5 \text{ Density of aqueous reagent solution (lb/gal) (For a 50% urea solution, as per page 1-27 of SNCR Manual)} \]
\[ M_{\text{reagent}} = 60.06 \text{ Molecular weight of reagent (grams/mol Urea)} \]
\[ M_{\text{NO}_2} = 46.01 \text{ Molecular weight of NO}_2\text{ (grams/mol NO}_2\text{)} \]
\[ SR_f = 2 \text{ Ratio of equivalent moles of NH}_3\text{ per mole of reagent (mols NH}_3\text{/mol Urea)} \]
\[ C_{\text{sol}} = 0.5 \text{ Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (assumption as per page 1-27 of SNCR Manual)} \]

Reagent mass flow rate:

\[ m_{\text{reagent}} = \frac{NO_{\text{s, in}} \times Q_{\text{in}} \times \eta_{\text{NO}} \times NSR \times M_{\text{reagent}}}{M_{\text{NO}_2} \times SR_f} \]

\[ m_{\text{reagent}} = 10.8 \text{ lbs/hr} \]

Aqueous reagent solution mass flow rate:

\[ m_{\text{sol}} = \frac{m_{\text{reagent}}}{C_{\text{sol}}} \]

\[ m_{\text{sol}} = 21.5 \text{ lbs/hr} \]

Solution volume flow rate:

\[ q_{\text{sol}} = \frac{m_{\text{sol}}}{\rho_{\text{sol}}} \]

\[ q_{\text{sol}} = 2.27 \text{ gph} \]

Aqueous reagent solution storage:

\[ V_{\text{tank}} = q_{\text{sol}} \times t_{\text{storage}} \]
\[ t_{\text{storage}} = 14.00 \text{ days (Assumption from pg. 1-27 in SNCR Manual)} \]
\[ V_{\text{tank}} = 761.68 \text{ gallons} \]

**TOTAL CAPITAL INVESTMENT, TC**

Cost \( C_{\text{Total}} = 2014 \)

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 facilities, land and working capital.

P:\PROJECTS\U.S. Steel\3410140066 - Mon Valley NOx VOC RACT FINAL DELIVERABLES\FINAL Irvin Appendix D - NOx Controls Cost Effectiveness - USS Irvin_FINAL 3-26-14 Appendix D - NOx Controls Cost Effectiveness - USS Irvin_FINAL 3-26-14.B1.SNCR
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numerical 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:**

\[
DC = \frac{5950}{MBtu/hr} \frac{M MBtu}{hr} \left( \frac{2375 MBtu}{hr} \right) \left( \frac{0.56 + 0.85 \eta_{net}}{Q_{hr}} \right) \]

\[
DC = \$ 825,823.75 \quad \text{(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574)}
\]

**Indirect Capital Costs:**

\[
\text{Total Indirect Installation Costs, IC} = DC \times (\text{General Facilities } \% + \text{Engineering and Home Office Fees } \% + \text{Process Contingency } \%)
\]

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

\[
\text{Project Contingency, C} = \frac{148,648.27}{DC + IC} = 15\%
\]

\[
\text{Total Plant Cost, D} = DC + IC + C = \$ 1,139,636.77
\]
Allowance for Funds During Construction, E = $ - (Assumed zero for SNCR)
Royalty Allowance, F = $ - (Assumed zero for SNCR)
Preproduction Costs, G = $ 22,792.74
Inventory Capital, H = $ 36,636.82 = \text{Vol}_{\text{reagent}} \times \text{Cost}_{\text{reagent}}$/gall
\text{Vol}_{\text{reagent}} = 198.4 gal/yr
\text{Cost}_{\text{reagent}} = 1.85 $/gal $/gallon (Mundel Price Index for January 2014, United States)
Initial Catalyst and Chemicals, I = $ - (Assumed zero for SNCR)
Total Capital Investment, TC1 = $ 1,109,066.33 = D + E + F + G + H + I

TOTAL ANNUAL COSTS

TAC = Total Annual Cost
\text{DAC} = \text{Direct Annual Costs}
\text{VAC} = \text{Variable and Semi-variable costs}

Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the SNCR.
Semi-variable includes: operating and supervisory labor and maintenance.

\text{DAC} = \left( \frac{\text{Annual Maintenance Cost}}{\text{Annual Reagent Cost}} \right) + \left( \frac{\text{Annual Electricity Cost}}{\text{Annual Water Cost}} \right) + \left( \frac{\text{Annual Fuel Cost}}{\text{Annual Fuel Cost}} \right)

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

Maintenance:
\text{Maintenance} = 1.5\% \text{ of TC1}
\text{Maintenance} = $ 17,986

Total operating time, t_{op} = \text{CF}_{\text{fuel}} \times 8,760 \text{ hrs/yr} = 8,760 \text{ hours} (CF not used as max hours required for RACT analysis)
Reagent Consumption (Urea):

\[ \text{Annual reagent cost} = \$ \times 36,737 = q_{\text{urea}} \times \text{cost}_{\text{urea}} \times t_{\text{op}} \]

Utilities:

Power Consumption, \( P \):

\[ P = 0.47 \times \frac{NO_{X_e} \times NSR \times Q_b}{9.5} \]

\( NO_{X_e} \) (uncontrolled) = 0.16 lb/MMBtu

\( NSR \) (Normalized Stoichiometric Ratio) = 2.86875

\( Q_b \), boiler heat input = 79.8 MMBtu/hr

\( P \) = 2 kw

\( t_{\text{op}} \) = 8760 hours

\( C_{\text{elec}} \) = 0.07 \$\text{kwh} \text{ (average 2014 cost from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)}

Annual electricity cost = \( P \times C_{\text{elec}} \times t_{\text{op}} = \$ \times 1.11 \text{ per kWh} \)

Water Consumption:

\[ q_{\text{water}} = \frac{m_{\text{ref}}}{\rho_{\text{water}}} \left( \frac{C_{\text{water,ref}}}{C_{\text{water}}} - 1 \right) \]

For a 50% solution dilution to a 10% solution, \( q_{\text{water}} \) becomes:

\[ q_{\text{water}} = 4 \times m_{\text{ref}} \]

\( \rho_{\text{water}} \) = 8.345 lb/gal

\( q_{\text{water}} \) = 0.01031 1000 gallons/hour

Annual water cost = \( q_{\text{water}} \times C_{\text{water}} \times t_{\text{op}} = \$ \times 1,000 \text{ gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial User http://www.earthbom...)}

\[ \text{Cost}_{\text{water}} = 8.37 \times 756.18 \]$
Additional Fuel Consumption:

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

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

\[
\Delta F_{\text{fuel}} \left( \frac{\text{MMBtu}}{\text{hr}} \right) = \frac{900 \left( \frac{\text{Btu}}{\text{lb}} \right)}{10^{1}} \times \frac{\text{lb}}{\text{MMBtu}} \times \frac{\text{lb}}{\text{hr}} \times 9
\]

\[
\Delta F_{\text{fuel}} \left( \frac{\text{MMBtu}}{\text{hr}} \right) = 0.0871
\]

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>MMBtu/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coke oven gas</td>
<td>26.8</td>
</tr>
<tr>
<td>Natural gas</td>
<td>9.20</td>
</tr>
<tr>
<td>Total MMBtu/hr</td>
<td>36.00</td>
</tr>
</tbody>
</table>

Percent usage:

- Coke oven gas: 0.74
- Natural gas: 0.26

Additional fuel required:

Natural gas: 0.08714 MMBtu/hr
Total cost associated with additional fuel usage:

<table>
<thead>
<tr>
<th>Natural gas cost</th>
<th>$9.44</th>
<th>$/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$7,205.97</td>
<td>$/yr</td>
</tr>
<tr>
<td>Total Natural gas</td>
<td>$7,205.97</td>
<td></td>
</tr>
<tr>
<td>Additional Energy Requirement</td>
<td>$2,876.478</td>
<td>(Additional heating of exhaust gas required for SNCR operations.)</td>
</tr>
</tbody>
</table>

Total DAC = $2,940,274.45

Indirect Annual Costs

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

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

Interest rate, i = 9.00% (US Steel Specific Interest Rate)

Economic life of SNCR, n = 20 years

CRF = 0.11

TCI = Total Capital Investment = $1,199,066.33

IDAC = $131,353.49

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC = $3,071,627.94

Total NOx removed = 25 tpy
COMPANY: United States Steel  
LOCATION: Irvin  
Source: Boiler #1  
NOX Emission Control Option: SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Unit Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td>0.07</td>
<td>Boiler Fuel Rating, mBtu/hr</td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td>9.00%</td>
<td>NOx Removal Efficiency, %</td>
</tr>
<tr>
<td>Water, $/1000 gal</td>
<td>8.37</td>
<td>Cost Year</td>
</tr>
<tr>
<td>NG, $/MMBtu/hr</td>
<td>9.44</td>
<td></td>
</tr>
<tr>
<td>Operating Labor, $/man-hr</td>
<td>70.00</td>
<td>Incremental Utility Requirements:</td>
</tr>
<tr>
<td>Manhours per year</td>
<td>547.5</td>
<td>Electricity, kw</td>
</tr>
<tr>
<td>Sales Tax, % of FOB</td>
<td></td>
<td>Reagent sol, gal/hr</td>
</tr>
<tr>
<td>Freight &amp; Ins. to Site, % of FOB</td>
<td>Included in DC</td>
<td>Water, 1,000 gal/hr</td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI</td>
<td>Included in DC</td>
<td></td>
</tr>
<tr>
<td>General Facilities, % DC</td>
<td>1.5%</td>
<td>NG, MMBtu/hr</td>
</tr>
<tr>
<td>Engineering and Home Office Fees % DC</td>
<td>5%</td>
<td>0.08714</td>
</tr>
<tr>
<td>Process Contingency % DC</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>Project Contingency % DC+IC</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Preproduction Costs % of D+E</td>
<td>15%</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reagent Volume, gallons</td>
</tr>
<tr>
<td></td>
<td></td>
<td>19804</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reagent Cost, $/gallon</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.85</td>
</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAQPS cost Manual 5th Ed.
1 - USS specific rates for utilities, interest and labor
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #1  
**NOx Emission Control Option:** SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th><strong>TOTAL CAPITAL INVESTMENT</strong></th>
<th><strong>TOTAL ANNUAL COST</strong></th>
<th><strong>COST EFFECTIVENESS</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Direct Capital Cost, DC</td>
<td>$825,824</td>
<td></td>
</tr>
<tr>
<td>Auxilliary Equipment (Heat Exchanger)</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Indirect Capital Costs:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Installation, IC</td>
<td>$165,165</td>
<td></td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>$148,648</td>
<td></td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td>$1,139,637</td>
<td></td>
</tr>
<tr>
<td>Allowance for Funds During Constr., E</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>Royalty Allowance,F</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>$22,793</td>
<td></td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td>$36,637</td>
<td></td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>**TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</td>
<td>$1,199,966</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>TOTAL ANNUAL COST</strong></th>
<th><strong>COST EFFECTIVENESS</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Annual Costs</td>
<td></td>
</tr>
<tr>
<td>Operating &amp; Supervisory Labor</td>
<td>$38,325</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$17,986</td>
</tr>
<tr>
<td>Reagent Consumption</td>
<td>$36,737</td>
</tr>
<tr>
<td>Utilities</td>
<td>$1,111</td>
</tr>
<tr>
<td>Water Consumption</td>
<td>$756</td>
</tr>
<tr>
<td>Add'l Fuel Usage (Process related)</td>
<td>$7,205.97</td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements (Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up in SNCR required temperature.)</td>
<td>$2,876,478</td>
</tr>
<tr>
<td><strong>Total Direct Annual Costs</strong></td>
<td>$2,978,599</td>
</tr>
<tr>
<td>Indirect Annual Costs</td>
<td></td>
</tr>
<tr>
<td>CRF</td>
<td>0.110</td>
</tr>
<tr>
<td>Total IDAC (CRF x TCI)</td>
<td>$131,353</td>
</tr>
<tr>
<td><strong>TOTAL ANNUAL COST, TAC (DAC + IDAC)</strong></td>
<td>$3,109,953</td>
</tr>
<tr>
<td>NOx removed, tpy</td>
<td>25.2</td>
</tr>
<tr>
<td>NOx, lbs/MMBtu</td>
<td>0.16</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>45%</td>
</tr>
<tr>
<td>Boiler Heat Input, MMBtu/hr</td>
<td>79.8</td>
</tr>
<tr>
<td>Total Operating Time, hrs/yr</td>
<td>8760</td>
</tr>
</tbody>
</table>

Cost Efficiency:  
Ston NOx removed | $123,579 | | |
SNCR Design Parameters used for Estimation

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

System Capacity Factor, \( CF_{\text{nomal}} = CF_{\text{plant}} \times CF_{\text{SNCR}} \)

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

\[
CF_{\text{plant}} = \frac{\text{FuelUsage}_{\text{annual, lbs}}}{\text{FuelUsage}_{\text{potential, lbs}}}
\]

\[
CF_{\text{Boiler#2}} = \frac{\text{Actual}_{2012, \text{ MMBtu/hr}}}{\text{Potential, MMBtu/hr}}
\]

\[
CF_{\text{SNCR}} = \frac{t_{\text{SNCR (days / yr)}}}{365 \ (\text{days / yr})}
\]

\[
CF_{\text{total}} = 0.52
\]

Uncontrolled \( \text{NO}_x \), Stack \( \text{NO}_x \) and \( \text{NO}_x \) Removal Efficiency

\[
\text{NO}_x_{\text{ars (uncontrolled)}} = 0.16 \ \text{lb/MMBtu (Potential)}
\]

\[
\text{NOX Removal Efficiency, } \eta_{\text{NOX}} = 45\%
\]

\[
\text{Stack } NO_x = 0.088 \ \text{lb/MMBtu (Estimated)}
\]

Normalized Stoichiometric Ratio, NSR

\[
NSR = \frac{2 \text{mol Urea}}{\text{mol NO}_x} \times NO_x + 0.7 \times \eta_{\text{NOX}}
\]

\[
NSR = 2.87
\]
Estimating Reagent Consumption

Reagent Consumption Parameters:

\[
\begin{align*}
N_{\text{reagent}} &= 9.5 \quad \text{Density of aqueous reagent solution (lb/gal) (For a 50\% urea solution, as per page 1-27 of SNCR Manual)} \\
M_{\text{reagent}} &= 60.06 \quad \text{Molecular weight of reagent (grams/mol Urea)} \\
M_{\text{NO}_x} &= 46.01 \quad \text{Molecular weight of NO}_x \text{ (grams/mol NO}_x) \\
SR &= 2 \quad \text{Ratio of equivalent moles of NH}_x \text{ per mole of reagent (mols NH}_x/\text{mol Urea)} \\
C_{\text{sol}} &= 0.5 \quad \text{Concentration of aqueous reagent solution by weight (lb reagents/lb solution) (assumption as per page 1-27 of SNCR Manual)}
\end{align*}
\]

Reagent mass flow rate:

\[
\dot{m}_{\text{reagent}} = \frac{N_{\text{reagent}} \times Q_{\text{in}} \times \eta_{\text{in}} \times SR \times M_{\text{reagent}}}{M_{\text{NO}_x} \times SR_f}
\]

\[
\dot{m}_{\text{reagent}} = 114.4 \quad \text{lbs/hr}
\]

Aqueous reagent solution mass flow rate:

\[
\dot{m}_{\text{sol}} = \frac{\dot{m}_{\text{reagent}}}{C_{\text{sol}}}
\]

\[
\dot{m}_{\text{sol}} = 22.8 \quad \text{lbs/hr}
\]

Solution volume flow rate:

\[
\dot{q}_{\text{sol}} = \frac{\dot{m}_{\text{sol}}}{\rho_{\text{sol}}}
\]

\[
\dot{q}_{\text{sol}} = 2.40 \quad \text{gph}
\]

Aqueous reagent solution storage:

\[
V_{\text{tank}} = \dot{q}_{\text{sol}} \times \dot{V}_{\text{storage}} = 14.00 \quad \text{days (Assumption from pg. 1-27 in SNCR manual)}
\]

\[
\dot{V}_{\text{storage}} = 14.00 \quad \text{days (Assumption from pg. 1-27 in SNCR manual)}
\]

\[
V_{\text{tank}} = 807.50 \quad \text{gallons}
\]

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 facilities, land and working capital.

P: PROJECTS\U.S. Steel\3410140966 - Mon Valley NOx VOC RACT FINAL DELIVERABLES\FINAL\Irvin\Appendix D - NOx Controls Cost Effectiveness - USS Irvin FINAL 3-26-14\Appendix D - NOx Controls Cost Effectiveness - USS Irvin FINAL 3-26-14B2 SNCR
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs DC associated with field measurements, numerical 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

\[ IC = \text{Indirect Capital} \]

\[ DC = \frac{950}{\text{MMBtu/hr}} Q_e \left( \frac{2375}{\text{MMBtu/hr}} \frac{\text{MMBtu/hr}}{hr} \right) \left( 0.66 + 0.85 \eta_{\text{DC}} \right) \]

DC = $846,482.16  (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 574)

Indirect Capital Costs:

\[ \text{Total Indirect Installation Costs, IC} = $169,266 \]

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

<table>
<thead>
<tr>
<th>General Facilities %</th>
<th>5%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering and Home Office Fees %</td>
<td>10%</td>
</tr>
<tr>
<td>Process Contingency %</td>
<td>5%</td>
</tr>
</tbody>
</table>

\[ \text{Project Contingency, C} = $152,366.79 \]

= 15% of DC + IC

\[ \text{Total Plant Cost, D} = $1,168,145.38 \]

= DC + IC + C
Allowance for Funds During Construction, $E = $ - (Assumed zero for SNCR)

Royalty Allowance, $F = $ - (Assumed zero for SNCR)

Preproduction Costs, $G = $23,362.91

Inventory Capital, $H = $38,840.54

Initial Catalyst and Chemicals, $I = $ - (Assumed zero for SNCR)

Total Capital Investment, $TCl = $1,230,348.83

TOTAL ANNUAL COSTS

\[ TAC = \text{Total Annual Cost} \]

\[ DAC = \text{Direct Annual Costs} \]

\[ \text{Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the SNCR.} \]

\[ \text{Semivariable include: operating and supervisory labor and maintenance.} \]

\[ DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Fuel}}{\text{Cost}} \right) \]

Operating and Supervisory Labor:

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

Maintenance:

\[ \text{Maintenance} = 1.5\% \text{ of } TCl \]

\[ \text{Maintenance} = \$18,455 \]

Total operating time, $t_{op} = CF_{fuel} \times 8760 \text{ hrs/yr} \]

8760 hours (CF not used as max hours required for RACT analysis)
Reagent Consumption (Urea):

\[ \text{Annual reagent cost} = \text{Cost}_{\text{reagent}} \times q_{\text{Urea}} \times t_{\text{op}} \]

Utilities:

Power Consumption, \( P \):

\[ P = 0.47 \times \frac{\text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{in}}}{0.5} \]

- \( \text{NOx}_{\text{in}} \) (uncontrolled) = 0.16 lb/MMBtu
- \( \text{NSR} \) (Normalized Stoichiometric Ratio) = 2.86875
- \( Q_{\text{in}} \), boiler heat input = 146 MMBtu/hr
- \( P = 2 \) kW
- \( \text{Cost}_{\text{elec}} = 0.07 \$ \text{kwh} \) (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.eia.gov)

\[ \text{Annual electricity cost} = P \times \text{Cost}_{\text{elec}} \times t_{\text{op}} = 1,178 \text{ per kWh} \]

Water Consumption:

\[ q_{\text{water}} = \frac{m_{\text{elec}}}{\rho_{\text{water}}} \left( \frac{C_{\text{in,water}} - C_{\text{out,water}}}{C_{\text{in,water}}} \right) \]

For urea dilution from a 50% solution to a 10% solution, \( q_{\text{water}} \) becomes:

\[ q_{\text{water}} = 4 \frac{m_{\text{elec}}}{\rho_{\text{water}}} \]

- \( \rho_{\text{water}} = 8.345 \text{ lb/gal} \)
- \( q_{\text{water}} = 0.01093 \text{ 1,000 gallons/hour} \)

\[ \text{Annual water cost} = q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} = 804.66 \text{ dollars} \]

(2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial User, 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 10% solution
- Heat of vaporization of water is 900 Btu/lb

\[
\Delta F_{\text{fuel}} \left( \frac{\text{MMBtu}}{\text{hr}} \right) = \frac{900 \left( \frac{\text{Btu}}{\text{lb}} \right) \times m_{\text{waste}} \left( \frac{\text{lb}}{\text{hr}} \right)}{10^3 \left( \frac{\text{Btu}}{\text{MMBtu}} \right)} \times 9
\]

\[
\Delta F_{\text{fuel}} \left( \frac{\text{MMBtu}}{\text{hr}} \right) = 0.0924
\]

Annual cost for additional fuel.

Average annual fuel consumption (calculated from 2012 fuel use data):

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>MMBtu/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coke oven gas</td>
<td>32.1</td>
</tr>
<tr>
<td>Natural gas</td>
<td>11.20</td>
</tr>
<tr>
<td>Total</td>
<td>43.30</td>
</tr>
</tbody>
</table>

Percent usage:

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Usage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coke oven gas</td>
<td>0.74</td>
</tr>
<tr>
<td>Natural gas</td>
<td>0.26</td>
</tr>
</tbody>
</table>

Additional fuel required:

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Required MMBtu/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>0.09238</td>
</tr>
</tbody>
</table>
Total cost associated with additional fuel usage:

Natural gas cost  $ 9.44  $/MMBtu

$ 7,639.41  $/yr

Total Natural gas: $ 7,639.41

Additional Energy Requirement = $ 3,060,572  (Additional heating of exhaust gas required for SNCR operations)

Total DAC = $ 3,127,933.79

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

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

Interest rate, i = 9.00%  (US Steel Specific Interest Rate)

Economic life of SNCR, n = 20 years

CRF = 0.11

TCI - Total Capital Investment - $ 1,230,348.83

IDAC = $ 134,780.38

Total Annual Cost:

Total Annual Cost, TAC = DAC + IDAC = $ 3,262,374.17

Total NOx removed = 26.7 tpy
**COMPANY:** United State Steel  
**LOCATION:** Irvin  
**Source:** Boiler #2  
**NOx Emission Control Option:** SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Utility Unit Costs</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Electricity, $/kwh</td>
<td>Equipment Life, yr</td>
</tr>
<tr>
<td></td>
<td>Interest Rate, %</td>
<td>Operating Hours Per Year</td>
</tr>
<tr>
<td></td>
<td>Water, $/1000 gal</td>
<td></td>
</tr>
<tr>
<td></td>
<td>NG, $/MMBtu</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Operating Labor, $/man-hr</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Manhours per year</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sales Tax, % of FOB</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Freight &amp; Ins. to Site, % of FOB</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Maintenance (Materials + Labor) % TCI</td>
<td></td>
</tr>
<tr>
<td></td>
<td>General Facilities, % DC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Engineering and Home Office Fees % DC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Process Contingency % DC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Project Contingency % DC+IC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Preproduction Costs % of D+E</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Incremental Utility Requirements</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Electricity, kw</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reagent sol, gal/hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Water, 1000 gal/hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NG, MMBtu/hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reagent Volume, gallons</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reagent Cost, $/gallon</td>
</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAO/PS cost Manual 5th Ed.

* U.S. specific rates for utilities, interest and labor.
COMPANY: United States Steel  
LOCATION: Irvin  
Source: Boiler #2  
NOx Emission Control Option: SNCR (45% Efficiency)

<table>
<thead>
<tr>
<th>TOTAL CAPITAL INVESTMENT</th>
<th>TOTAL ANNUAL COST</th>
<th>COST EFFECTIVENESS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Direct Capital Cost, DC</strong></td>
<td><strong>$846,482</strong></td>
<td></td>
</tr>
<tr>
<td>Auxiliary Equipment (Heat Exchanger)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Direct Capital costs includes PEC such as SNCR system equipment, installation, sales tax and freight. Cost for heat exchanger not included.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Indirect Capital Costs:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td><strong>$169,296</strong></td>
<td></td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td><strong>$152,367</strong></td>
<td></td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td><strong>$1,168,145</strong></td>
<td></td>
</tr>
<tr>
<td>Allowance for Funds During Constr., E</td>
<td><strong>$-</strong></td>
<td></td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td><strong>$-</strong></td>
<td></td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td><strong>$23,363</strong></td>
<td></td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td><strong>$38,841</strong></td>
<td></td>
</tr>
<tr>
<td>Initial Catalyst and Chemicals, I</td>
<td><strong>$-</strong></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</strong></td>
<td><strong>$1,230,349</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Total Direct Annual Costs</strong></td>
<td><strong>$3,127,594</strong></td>
<td></td>
</tr>
<tr>
<td>Direct Annual Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating &amp; Supervisory Labor</td>
<td><strong>$0</strong></td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td><strong>$18,455</strong></td>
<td></td>
</tr>
<tr>
<td>Reagent Consumption</td>
<td><strong>$38,947</strong></td>
<td></td>
</tr>
<tr>
<td>Utilities</td>
<td><strong>$1,178</strong></td>
<td></td>
</tr>
<tr>
<td>Water Consumption</td>
<td><strong>$802</strong></td>
<td></td>
</tr>
<tr>
<td>Add'l Fuel Usage (Process related)</td>
<td><strong>$7,639.41</strong></td>
<td></td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements</td>
<td><strong>$3,060,572</strong></td>
<td></td>
</tr>
<tr>
<td>Auxiliary Heating Costs = Nat'g gas cost required to heat boiler exhaust up to SNCR required temperature.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Indirect Annual Costs</strong></td>
<td><strong>$134,780</strong></td>
<td></td>
</tr>
<tr>
<td>CRF</td>
<td><strong>0.110</strong></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL ANNUAL COST, TAC (DAC + IDAC)</strong></td>
<td><strong>$3,262,374</strong></td>
<td></td>
</tr>
</tbody>
</table>

Cost Efficiency:  
S/ton NOx removed  
$122,280  
NOx removed, tpy  
26.7  
Efficiency, %  
45%  
NOx, lbs/MMBtu  
0.16  
Boiler Heat Input, MMBtu/hr  
84.6  
Total Operating Time, hrs/yr  
8769
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** 80" Hot Strip Reheat Furnace  
**NOx Emission Control Option:** Ultra Low NOx Burners

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Unit Costs</td>
<td>Equipment Life, yr</td>
<td>Furnace Fuel Rating, mmBtu/hr</td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td>10.0</td>
<td>140</td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td>Operating Hours Per Year</td>
<td>NOx Removal Efficiency, %</td>
</tr>
<tr>
<td>9.00%</td>
<td>8760</td>
<td>58%</td>
</tr>
</tbody>
</table>

**Operating Costs**

<table>
<thead>
<tr>
<th>Direct Installation</th>
<th>Incremental Utility Requirement, kwh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Labor, $/hr</td>
<td>70.00</td>
</tr>
<tr>
<td>Manhours per year</td>
<td>0</td>
</tr>
<tr>
<td>Maintenance (Materials + Labor), % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Property Tax, % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Insurance, % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Administration, % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Overhead, % Labor &amp; Maintenance</td>
<td>60%</td>
</tr>
<tr>
<td><strong>Project Contingency, % DC+IC</strong></td>
<td>20%</td>
</tr>
</tbody>
</table>

**Direct Costs**

<table>
<thead>
<tr>
<th>Indirect Costs</th>
<th>Total Indirect, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales Tax, % of FOB</td>
<td>7%</td>
</tr>
<tr>
<td>Freight &amp; Ins. to Site, % of FOB</td>
<td>5%</td>
</tr>
<tr>
<td>Instrumentation</td>
<td>10%</td>
</tr>
</tbody>
</table>

Note: Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for firing and OAQPS cost Manual 5th Ed.
1 - USS specific rates for utilities, interest and labor.
2 - Equipment life based upon facility experience and history.
3 - NOx emission rates based upon actual USS Granite City limits for the same type of burners and same type of sources.
COMPANY: United States Steel  
LOCATION: Irvin  
Source: 80" Hot Strip Reheat Furnace  
NOx Emission Control Option: Ultra Low NOx Burners

<table>
<thead>
<tr>
<th>TOTAL CAPITAL INVESTMENT</th>
<th>TOTAL ANNUAL COST</th>
<th>COST EFFECTIVENESS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Direct Capital Cost, DC</strong></td>
<td><strong>Direct Annual Costs</strong></td>
<td><strong>NOx removed, tpy</strong></td>
</tr>
<tr>
<td>Vendor Quoted Cost for Burners Only</td>
<td>Operating &amp; Supervisory Labor</td>
<td>36</td>
</tr>
<tr>
<td>Upgrade to meet NFPA Requirements</td>
<td>Maintenance</td>
<td>15</td>
</tr>
<tr>
<td>CEMS and PLC Instrumentation</td>
<td>Reagent Consumption</td>
<td>58</td>
</tr>
<tr>
<td>Additional Combustion air fans</td>
<td>Utilities</td>
<td>58</td>
</tr>
<tr>
<td>Refractory Replacement</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Capital</strong></td>
<td><strong>Total Direct Annual Costs</strong></td>
<td><strong>Cost Efficiency:</strong></td>
</tr>
<tr>
<td>$793,478</td>
<td>$52,301</td>
<td>$8,364</td>
</tr>
<tr>
<td>$387,600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$618,715</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$90,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$75,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$1,964,793</td>
<td>$73,763</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
1 - Vendor quote for same setup and requirements for similar reheat furnaces at USS Granite City facility.  
2 - Estimates based upon knowledge of the process and vendor requirements for upgrade.  
3 - NOx emission rates based upon actual USS Granite City Limits for the same type of burners and same type of sources.
## Company: United States Steel
## Location: Irwin
## Source: Boiler #1

**NOx Emission Control Option: Low NOx Burners**

### Site Information

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Unit Costs</td>
<td></td>
</tr>
<tr>
<td>Electricity, $/kwh</td>
<td>0.97</td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td>9.00%</td>
</tr>
<tr>
<td>Operating Costs</td>
<td></td>
</tr>
<tr>
<td>Operating Labor, $/man-hr</td>
<td>70.00</td>
</tr>
<tr>
<td>Manhours per year</td>
<td>0</td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Property Tax % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Insurance, % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Administration, % of TCI</td>
<td>1%</td>
</tr>
<tr>
<td>Overhead, % Labor &amp; Maintenance</td>
<td>60%</td>
</tr>
<tr>
<td>Project Contingency % DC+IC</td>
<td>20%</td>
</tr>
</tbody>
</table>

### Source Emission Information

<table>
<thead>
<tr>
<th>Item</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment Life, yr</td>
<td>20.0</td>
</tr>
<tr>
<td>Operating Hours Per Year</td>
<td>8760</td>
</tr>
<tr>
<td>Foundations and Supports</td>
<td>4%</td>
</tr>
<tr>
<td>Handling and erection</td>
<td>50%</td>
</tr>
<tr>
<td>Electrical</td>
<td>8%</td>
</tr>
<tr>
<td>Piping</td>
<td>1%</td>
</tr>
<tr>
<td>Insulation</td>
<td>7%</td>
</tr>
<tr>
<td>Painting</td>
<td>4%</td>
</tr>
<tr>
<td>Building preparation</td>
<td>0%</td>
</tr>
<tr>
<td>Total Installation</td>
<td>74%</td>
</tr>
</tbody>
</table>

### Control Technology Information

<table>
<thead>
<tr>
<th>Item</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Furnace Fuel Rating, mmBTU/hr</td>
<td>80</td>
</tr>
<tr>
<td>NOx Removal Efficiency, nox</td>
<td>25%</td>
</tr>
<tr>
<td>Cost Year</td>
<td>2014</td>
</tr>
<tr>
<td>Incremental Utility Requirement</td>
<td></td>
</tr>
<tr>
<td>Additional Fan Electricity, kw</td>
<td>0</td>
</tr>
<tr>
<td>Indirect Costs</td>
<td></td>
</tr>
<tr>
<td>Construction and Field, % DC</td>
<td>10%</td>
</tr>
<tr>
<td>Engineering and Home Office Fees % DC</td>
<td>20%</td>
</tr>
<tr>
<td>Construction Fee % DC</td>
<td>10%</td>
</tr>
<tr>
<td>Performance Test, % DC</td>
<td>1%</td>
</tr>
<tr>
<td>Startup, % DC</td>
<td>2%</td>
</tr>
<tr>
<td>Total Indirect</td>
<td>43%</td>
</tr>
</tbody>
</table>

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers," Section 6 for natural gas firing and OAQPS Cost Manual 5th Ed.

1. US$ specific rates for utilities, interest and labor.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #1  
**NOX Emission Control Option:** Low NOx Burners

<table>
<thead>
<tr>
<th>TOTAL CAPITAL INVESTMENT</th>
<th>TOTAL ANNUAL COST</th>
<th>COST EFFECTIVENESS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Vendor Quoted Cost for Burners Only</strong> $200,000</td>
<td><strong>Direct Annual Costs</strong></td>
<td>NOX_{all, Potential} lbs/MMBtu 0.16</td>
</tr>
<tr>
<td><strong>Instrumentation</strong> $20,000</td>
<td><strong>Operating &amp; Supervisory Labor</strong> $-</td>
<td>Emissions After Control lbs/MMBtu 0.12</td>
</tr>
<tr>
<td><strong>New Refractory and Windbox</strong> $50,000</td>
<td><strong>Maintenance</strong> $7,720</td>
<td>Efficiency, % 25%</td>
</tr>
<tr>
<td><strong>CFD Modeling</strong> $20,000</td>
<td><strong>Reagent Consumption</strong> $-</td>
<td>Heat Input, MMBtu/hr 80</td>
</tr>
<tr>
<td><strong>Total Capital</strong> $290,000</td>
<td><strong>Utilities</strong> $-</td>
<td>Total Operating Time, hrs/yr 8760</td>
</tr>
<tr>
<td><strong>Sales Tax</strong> $20,300</td>
<td><strong>Auxiliary Equipment Requirements</strong> $-</td>
<td></td>
</tr>
<tr>
<td><strong>Freight &amp; Ins. to Site</strong> $14,500</td>
<td>(Auxiliary Heating Costs) $-</td>
<td>NOX$_x$ removed, tpy 14</td>
</tr>
<tr>
<td><strong>Direct Costs DC</strong> $324,800</td>
<td><strong>Total Direct Annual Costs</strong> $7,720</td>
<td>Cost Efficiency: $/ton NOX$_x$ removed $8,257</td>
</tr>
<tr>
<td><strong>Total Indirect Capital Costs:</strong></td>
<td><strong>Indirect Annual Costs</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Indirect Capital, IC</strong> $139,664</td>
<td><strong>Overhead</strong> 0.0</td>
<td></td>
</tr>
<tr>
<td><strong>Project Contingency, C</strong> $92,897</td>
<td><strong>Property Tax</strong> $7,720</td>
<td></td>
</tr>
<tr>
<td><strong>Total Plant Cost, D (DC + IC + C)</strong> $557,357</td>
<td><strong>Insurance</strong> $7,720</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Administration charges</strong> $7,720</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Capital Recovery, CRF</strong> 0.11</td>
<td>$23,159</td>
</tr>
<tr>
<td></td>
<td><strong>IDAC (CRF x TCI)</strong> $84,565</td>
<td></td>
</tr>
</tbody>
</table>

**TOTAL CAPITAL INVESTMENT, TCI/(D+E+F+G+H)** $771,957  
**TOTAL ANNUAL COST, TAC** $115,443

**Notes:**  
1. Cost estimates and NOx emission rates based upon burner vendor (John Zinc Hamworthy) submittal and follow-up discussions.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #2  
**NOx Emission Control Option:** Low NOx Burners

<table>
<thead>
<tr>
<th>Site Information</th>
<th>Source Emission Information</th>
<th>Control Technology Information</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Utility Unit Costs</strong></td>
<td><strong>Equipment Life, yr</strong></td>
<td><strong>Eutrance Fuel Rating, mmBtu/hr</strong></td>
</tr>
<tr>
<td>Electricity, $/kwb</td>
<td>0.97</td>
<td>85</td>
</tr>
<tr>
<td>Interest Rate, %</td>
<td>9.80%</td>
<td>25%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th><strong>Operating Hours Per Year</strong></th>
<th><strong>NOx Removal Efficiency, bmo</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Costs</td>
<td>8760</td>
<td>2014</td>
</tr>
<tr>
<td>Operating Labor, $/man-hr</td>
<td>$0.00</td>
<td>Incremental Utility Requirement</td>
</tr>
<tr>
<td>Manhours per year</td>
<td>0</td>
<td>Additional Fan Electricity, kw</td>
</tr>
<tr>
<td>Maintenance (Materials + Labor) % TCI</td>
<td>1%</td>
<td>0</td>
</tr>
</tbody>
</table>
| Property Tax, % of TCI | 1% | 4%
| Insurance, % of TCI | 1% | 50%
| Administration, % of TCI | 1% | Electrical |
| Overhead, % Labor & Maintenance | 60% | 8%
| Project Contingency % DC+IC | 20% | Piping |

<table>
<thead>
<tr>
<th></th>
<th><strong>Building preparation</strong></th>
<th><strong>Building preparation</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Foundations and supports</td>
<td>4%</td>
<td>Indirect Costs</td>
</tr>
<tr>
<td>Handling and erection</td>
<td>50%</td>
<td>Construction and Field, % DC</td>
</tr>
<tr>
<td>Electrical</td>
<td>8%</td>
<td>Engineering and Home Office Fees, % DC</td>
</tr>
</tbody>
</table>
| Piping | 1% | 10%
| Insulation | 7% | Construction Fee, % DC |
| Painting | 4% | 10%
| | 0% | Performance Test, % DC |
| | 74% | Startup, % DC |
| | Total Installation | 43% |

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

Costing elements based upon the 1997 EPA Alternative Control Techniques (ACT) document for "NOx controls for institutional, commercial and industrial (ICI) boilers." Section 6 for natural gas firing and OAPPS cost Manual 5th Ed.  
1 - USS specific rates for utilities, interest and labor.
**COMPANY:** United States Steel  
**LOCATION:** Irvin  
**Source:** Boiler #2  
**NOX Emission Control Option:** Low NOx Burners

### TOTAL CAPITAL INVESTMENT

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quoted cost for Capital, DC</td>
<td>$214,177</td>
</tr>
<tr>
<td>Instrumentation</td>
<td>$21,418</td>
</tr>
<tr>
<td>New Refractory and Windbox</td>
<td>$53,544</td>
</tr>
<tr>
<td>CFD Modeling</td>
<td>$20,000</td>
</tr>
<tr>
<td>Total Capital, DC</td>
<td>$309,139</td>
</tr>
<tr>
<td>Freight &amp; Ins. to Site</td>
<td>$15,457</td>
</tr>
<tr>
<td>Direct Costs DC</td>
<td>$364,236</td>
</tr>
<tr>
<td>Indirect Capital, IC</td>
<td>$148,881</td>
</tr>
<tr>
<td>Project Contingency, C</td>
<td>$99,023</td>
</tr>
<tr>
<td>Total Plant Cost, D (DC + IC + C)</td>
<td>$594,141</td>
</tr>
<tr>
<td>Direct Installation</td>
<td>$228,763</td>
</tr>
<tr>
<td>Royalty Allowance, F</td>
<td>-</td>
</tr>
<tr>
<td>Preproduction Costs, G</td>
<td>-</td>
</tr>
<tr>
<td>Inventory Capital, H</td>
<td>-</td>
</tr>
</tbody>
</table>

**TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H)** = $822,904

### TOTAL ANNUAL COST

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating &amp; Supervisory Labor</td>
<td>-</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$8,229</td>
</tr>
<tr>
<td>Reagent Consumption</td>
<td>-</td>
</tr>
<tr>
<td>Utilities</td>
<td>-</td>
</tr>
<tr>
<td>Auxiliary Equipment Requirements</td>
<td>-</td>
</tr>
<tr>
<td>(Auxiliary Heating Costs)</td>
<td>-</td>
</tr>
<tr>
<td>Total Direct Annual Costs</td>
<td>$8,229</td>
</tr>
</tbody>
</table>

**Indirect Annual Costs**

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead</td>
<td>0.0</td>
</tr>
<tr>
<td>Property Tax</td>
<td>$8,229</td>
</tr>
<tr>
<td>Insurance</td>
<td>$8,229</td>
</tr>
<tr>
<td>Administration charges</td>
<td>$8,229</td>
</tr>
<tr>
<td>Capital Recovery, CRF</td>
<td>$24,687</td>
</tr>
<tr>
<td>IDAC (CRF x TCI)</td>
<td>$90,146</td>
</tr>
</tbody>
</table>

**TOTAL ANNUAL COST, TAC** = $123,062

### COST EFFECTIVENESS

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOX annual lbs/MMBtu</td>
<td>0.15</td>
</tr>
<tr>
<td>Emissions After Control lbs/MA</td>
<td>0.12</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>25%</td>
</tr>
<tr>
<td>Heat Input, MMBtu/hr</td>
<td>85</td>
</tr>
<tr>
<td>Total Operating Time, hrs/yr</td>
<td>8760</td>
</tr>
<tr>
<td>NOx removed, tpy</td>
<td>15</td>
</tr>
</tbody>
</table>

**Cost Efficiency:**  
$/ton NOx removed = $8,303

---

**Notes:**  
1. Cost estimates and NOx emission rates based upon vendor (John Zinc Hamworthy) submittal and follow-up discussions.
ALLEGHENY COUNTY HEALTH DEPARTMENT

IN RE:
USX Corporation
U.S. Steel Group
Irvin Works PA 15207
Allegheny County
Dravosburg, PA 15034

PLAN APPROVAL ORDER
AND AGREEMENT No. 258
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 USX Corporations, U.S. Steel Group, (hereafter referred to as "USX"), 600 Grant Avenue, Allegheny County, Pittsburgh, PA 15219, as the operator and the owner of a steel processing facility at Camp Hollow Road, Allegheny County, West Mifflin, PA 15122, (hereafter referred to as the "Irvin Plant"), is a major stationary source of oxides of nitrogen and volatile organic compounds (hereafter referred to as "NOx" 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 of Article XXI, entitled "Major Sources of Nitrogen Oxides and Volatile Organic Compounds is applicable to Irvin Plant's operations; and

WHEREAS, USX 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 emissions of NOx and VOCs from the Irvin Plant; and

WHEREAS, the Department and USX desire to memorialize 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;

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. Irvin Plant shall maintain and operate the following equipment in accordance with good combustion and air pollution control practices and air pollution control practices, at all times with the exception of emergency or planned outages, repairs or maintenance.

1. Boilers #1, #2, #3 and #4
2. 80" Hot Strip Mill Reheat Furnaces 1 through 5
3. No. 1 Galvanizing Line Furnace
4. No. 1 Galvanneal Furnace 6
5. No. 2 Galvalume Furnace
6. Terne Line Pot Heater
7. Open Coil Annealing Furnace
8. No. 2 Continuous Annealing Furnace
9. HPH Box Annealing Furnace
10. 80" Hot Strip Mill Rolling Stands
11. Five Stand Cold Rolling Mill

1.2 Irvin Plant shall conduct an annual adjustment on the combustion processes of the following equipment:

1. 80" Hot Strip Mill Reheat Furnaces #1
through #5

2. Boilers #1, #2, #3 and #4

3. No. 2 Continuous Annealing Furnace

Such annual adjustment shall include:

a. Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

b. Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NO\textsubscript{x}, and to the extent practicable minimize emissions of carbon monoxide (hereafter referred as "CO"; and

c. Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Irvin Plant shall maintain the following records of the for the subject equipment:
a. the date of the annual tune-up;
b. the name of the service company and/or individuals performing the annual tune-up;
c. the operating rate or load after the annual tune-up;
d. the CO and NO\textsubscript{x} emission rate after the annual tune-up; and

1.3 Irvin Plant shall operate the No. 3 Five Stand Cold Rolling Mill and the 80" Hot Strip Mill Rolling Stand with lubricating oil, which is an oil-water emulsion and does not exceed a maximum VOC content by weight, of 2% and 4%, respectively.

1.4. Irvin Plant shall maintain all appropriate records to demonstrate compliance with the requirements of both Section 2105.06 Article XXI and this Order.

1.5. Irvin Plant shall retain all records required by both Section 2105.06 of Article XXI and this Order for the facility for at least two (2) years and shall make the same available to the Department upon request.
II. AGREEMENT

The foregoing Plan Approval Order shall be enforced in accordance with and is subject to the following agreements of the parties, to wit:

2.1. The contents of this Order shall be submitted to the U.S. EPA as a revision to Allegheny County's portion of the Commonwealth of Pennsylvania's State Implementation Plan.

2.2. Failure to comply with any portion of this Order or Agreement is a violation of Article XXI that may subject USX 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.

2.5. USX acknowledges and understands that the purpose of this Agreement is to establish RACT for the control of emissions of NOx and VOC emissions from the Irvin Plant. USX further acknowledges and understands the possibility that the U.S. EPA may decide to not accept the Agreement portion of this RACT 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: D. H. Lohr
Title: General Manager
Mon Valley Works
Date: 12/17/96

ALLEGHENY COUNTY HEALTH DEPARTMENT
By: [Signature] 1/30/96
Bruce W. Dixon, M.D., Director
Allegheny County Health Department

and By: [Signature]

Thomas J. Puzniak, Engineering Manager
Air Quality Program
ALLEGHENY COUNTY HEALTH DEPARTMENT

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1891

*Title V Operating Permit*

&

*Federally Enforceable State Operating Permit*

**Issued To:** U. S. Steel Mon Valley Works - Irvin Plant
**Facility:** U. S. Steel Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

**ACHD Permit #:** 0050-OP16b
**Date of Issuance:** December 9, 2016
**Amendment Date:** April 16, 2020
**Expiration Date:** December 8, 2021
**Renewal Date:** June 9, 2021

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

**Prepared By:** Gregson Vaux
Air Quality Engineer

Digitally signed by JoAnn Truchan, PE
Date: 2020.04.16 10:36:45 -04'00'

Digitally signed by Gregson Vaux
Date: 2020.04.16 11:22:02 -04'00'
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<thead>
<tr>
<th>DATE</th>
<th>SECTION(S)</th>
</tr>
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<tr>
<td>05/22/19</td>
<td>Condition IV.26: Added SIP SO₂ requirements; Conditions V.A.1.g, V.E.1.f, V.F.1.o, V.G.1.h, V.K.1.g &amp; V.L.1.g: Added SO₂ emissions limit table; Condition V.A.2.a: Revised SO₂ emissions test; Conditions V.E.2.a, V.F.2.a, V.G.2.a, V.K.2.a, V.L.2.a, V.M.2.a &amp; V.M.2.a: Added SO₂ emissions test; Conditions V.A.3.a, V.E.3.a, V.F.3.a, V.G.3.a: Revised the COG monitoring condition; Conditions V.A.4.b, V.E.4.a, V.F.4.a, V.G.4.b, V.K.4.b, V.L.4.b, V.M.4.b &amp; V.N.4.b: Revised the COG concentration recordkeeping; Conditions V.A.5.b, V.E.5.b, V.F.5.a, V.G.5.a, V.K.5.a, V.L.5.a, V.M.5.a &amp; V.N.5.a: Revised the conditions.</td>
</tr>
<tr>
<td>04/16/20</td>
<td>Incorporated case-by-case RACT conditions and citations.</td>
</tr>
</tbody>
</table>
I. CONTACT INFORMATION

Facility Location: U. S. Steel Mon Valley Works – Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

Permittee/Owner: U. S. Steel Mon Valley Works – Irvin Plant
Camp Hollow Road
West Mifflin, PA 15122

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) 675-7822

Facility Contact: Nicole Heinichen
Title: Environmental Engineer
Telephone Number: (412) 675-7382
Fax Number: (412) 675-7822
E-mail Address: nlheinichen@uss.com

AGENCY ADDRESSES:

ACHD Contact: Chief Engineer
Allegheny County Health Department
Air Quality Program
301 39th Street, Building #7
Pittsburgh, PA 15201-1891

ACHD Engineer: Gregson Vaux
Title: Air Quality Engineer
Telephone Number: 412-578-8148
Fax Number: 412-578-8144
E-mail Address: gregson.vaux@alleghenycounty.us

EPA Contact: Enforcement Programs Section (3AP12)
USEPA Region III
1650 Arch Street
Philadelphia, PA 19103-2029
II. FACILITY DESCRIPTION

The U. S. Steel Irvin Works is a secondary steel processing facility located in West Mifflin Borough, Allegheny County, Pennsylvania. The Irvin Plant receives steel slabs and performs one of several finishing processes on the steel slabs. The finishing processes commonly referred to as secondary steel processes, include hot and cold rolling, continuous pickling, annealing, and galvanizing. The facility is composed of an 80" hot strip mill, 64" & 84" continuous hydrochloric acid pickle lines, a cold reduction mill, HPH annealing furnaces, open coil annealing furnaces, a continuous annealing furnace, continuous galvanizing line no. 1, continuous galvanizing and aluminum coating line no. 2, a continuous terne line, four coke oven gas flares, and four natural gas/coke oven gas fired boilers.

The emission units regulated by this permit are summarized in Table II-1:

<table>
<thead>
<tr>
<th>I.D.</th>
<th>SOURCE DESCRIPTION</th>
<th>CONTROL DEVICE(S)</th>
<th>MAXIMUM CAPACITY</th>
<th>FUEL/RAW MATERIAL</th>
<th>STACK I.D.</th>
</tr>
</thead>
<tbody>
<tr>
<td>P001 to P005</td>
<td>80-Inch Hot Strip Mill Reheat Furnaces No. 1 to No. 5</td>
<td>None</td>
<td>140 MMBtu/Hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP1 to SP6</td>
</tr>
<tr>
<td>P016</td>
<td>Scale Breaker Roughing Mill &amp; Finishing Mill</td>
<td>None</td>
<td>3,000,000 tons/yr</td>
<td>NA</td>
<td>Fugitive</td>
</tr>
<tr>
<td>P002</td>
<td>64-Inch Continuous Coil Hydrochloric Acid Pickle Line</td>
<td>Packed Tower Scrubber</td>
<td>1,047,174 tons/yr</td>
<td>Steel Coils, HCl Pickle Liquor</td>
<td>SP023</td>
</tr>
<tr>
<td>P007</td>
<td>84-Inch Continuous Coil Hydrochloric Acid Pickle Line</td>
<td>Packed Tower Scrubber</td>
<td>1,576,800 tons/yr</td>
<td>Steel Coils, HCl Pickle Liquor</td>
<td>SP7</td>
</tr>
<tr>
<td>P008</td>
<td>Cold Reduction Mill (Mill Stands No. 1 to No. 5)</td>
<td>Cyclone Mist Eliminator</td>
<td>3,767,676 tons/yr</td>
<td>Steel Coils and Rolling Oil Solution</td>
<td>SP9</td>
</tr>
<tr>
<td>P009</td>
<td>HPH Batch Annealing Furnaces (31 individual furnaces)</td>
<td>None</td>
<td>4.9 MMBtu/hr, each furnace</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP10</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnaces No. 1 to No. 9</td>
<td>None</td>
<td>7.2 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnaces No. 10 to No. 13</td>
<td>None</td>
<td>9.0 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnace No. 14</td>
<td>None</td>
<td>5.4 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P010</td>
<td>Open Coil Annealing Furnace No. 15 &amp; No. 16</td>
<td>None</td>
<td>7.47 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP12</td>
</tr>
<tr>
<td>P011</td>
<td>Continuous Annealing</td>
<td>None</td>
<td>45 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SP13</td>
</tr>
<tr>
<td>P012</td>
<td>No.1 Continuous Galvanizing Preheat Furnace</td>
<td>None</td>
<td>50 MMBtu/hr</td>
<td>Natural Gas</td>
<td>SP16</td>
</tr>
<tr>
<td>P012</td>
<td>No. 1 Continuous Galvanizing Galvanneal Furnace</td>
<td>None</td>
<td>18 MMBtu/hr</td>
<td>Natural Gas</td>
<td>SP16</td>
</tr>
<tr>
<td>No.</td>
<td>Description</td>
<td>Fuel</td>
<td>Btu/hr</td>
<td>Source</td>
<td>SPA</td>
</tr>
<tr>
<td>-----</td>
<td>-----------------------------------------------------------------</td>
<td>---------------</td>
<td>---------</td>
<td>----------------------</td>
<td>-----</td>
</tr>
<tr>
<td>P013</td>
<td>No. 2 Continuous Galvanizing Galvalum Preheat Furnace</td>
<td>None</td>
<td>18MMBtu/hr</td>
<td>Natural Gas</td>
<td>SP18</td>
</tr>
<tr>
<td>P015</td>
<td>Coke Oven Gas Flares No. 1 to No.3 (5 lines)</td>
<td>None</td>
<td>6.75 MMSCF/d, each</td>
<td>Coke Oven Gas</td>
<td>SP20</td>
</tr>
<tr>
<td>P015</td>
<td>Peachtree Coke Oven Gas Flare (Line A and B)</td>
<td>None</td>
<td>6.75 MMSCF/d</td>
<td>Coke Oven Gas</td>
<td>SP21</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler No. 1</td>
<td>None</td>
<td>79.8 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB1</td>
</tr>
<tr>
<td>B001</td>
<td>Boiler No. 2</td>
<td>None</td>
<td>84.6 MMBtu/hr</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB2</td>
</tr>
<tr>
<td>B003</td>
<td>Boiler No. 3</td>
<td>None</td>
<td>41.6 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB3</td>
</tr>
<tr>
<td>B004</td>
<td>Boiler No. 4</td>
<td>None</td>
<td>41.6 MMBtu/hr, each</td>
<td>Coke Oven Gas and Natural Gas</td>
<td>SB3</td>
</tr>
</tbody>
</table>
Figure II-1: 80-Inch Hot Strip mill Reheat Furnaces and Roughing & Finishing Mills

- Reheat Furnace No. 1 → SP-1 & SP-6
- Reheat Furnace No. 2 → SP-2 & SP-6
- Reheat Furnace No. 3 → SP-3 & SP-6
- Reheat Furnace No. 4 → SP-4
- Reheat Furnace No. 5 → SP-5

Roughing Mill → Descaling Operations → Finishing Mill

Fugitive-Inside Building
Figure II-2: 64-inch Continuous Coil HCl Pickle Line

Steel Coils

Tension leveler/
Scale Breaker

Four (4) Continuous
HCl Tanks in Series

Rinse Tank

Finished Coils

Continuous collection system covers integral with the HCl tanks

Four (4)
HCl Storage
Tanks

Wet Packed
Tower Fume
Scrubber

SP023

SP500

HCl to Pickle Line

Air
Emissions

Process Flow
Figure II-3: 84-inch Continuous Coil Pickle Line

*The Water Wash Scrubber is a Packed Tower Water Scrubber
Figure II-4: Cold Reduction Mill

Steel coils

Mill Stand No. 1

Mill Stand No. 2

Mill Stand No. 3

Mill Stand No. 4

Mill Stand No. 5

Capture System with Mist Eliminators

SP9
Figure II-5: HPH Annealing Furnaces

NOTES:

1. Annealing gases (hydrogen and nitrogen) are not regulated air pollutants
2. 31 individual furnaces; 29 furnace stacks and atmosphere purge stacks; 58 bases.
NOTES:

1. Annealing gases (hydrogen and nitrogen) are not regulated air pollutants.
2. Sixteen (16) moveable furnaces, 24 bases – all share a single duct.
3. Emissions from annealing furnace combustion, annealing gases, and cooling beds combine into one duct which then splits into 3 stacks.
Figure II-7: Continuous Annealing Line

- **Steel Coils**
- **Uncoiler/Welder/Tension Control/Shear**
- **Electro-Cleaner**
- **Brush Scrubber & Hot Rinse Dryer**
- **Entry Looping Tower/Pit**
- **Annealing Furnace**
- **1st & 2nd Cooling Zone**
- **Exiting Looping Tower/Pit**
- **Shear/Coiler**
- **Steel Coils**

Flow Diagram:
- **Fugitive Emissions**
- **Condenser**
- **Condenser Fumes/Filtered Water**
- **Wastewater Treatment**
- **Water**
- **Non-Contact Steam**
- **Caustic Storage**
- **Wastewater Treatment**
- **Scotland**
- **Combustion Emissions**

Additional Notes:
- **Scrap Steel**
- **Controlled Waste**
- **[To # 7 Temper Mill & #17 Recoiler]**

**Title V Operating Permit No. 0050-OP16b**

Amended: April 16, 2020
Figure II-8: No. 1 Continuous Galvanizing Line
Figure II-10: No. 2 Continuous Galvanizing Line

- Steel Coils
- Uncoiler Shear/Welder
- Caustic Cleaning
- Rinse
- Strip Dryers Steam Heat
- Preheat Furnace
- Annealing Furnace (Electric)
- Annealing Gases
- Annealing Gases Purge
- Combustion Emissions
- Galvalume Pot
- Galvalume & Flux Agents
- Zinc Pot
- Fugitive Emissions
- Scrubber Water
- N.G. Water
- Basement Holding Tank
- Coiler/Shear
- Strip Oiler
- Air Dryer
- Chem Treat Tank
- NDS Unit
- Infrared Oven/Roll Coater
- 4 High Temper Mill
- Quench Tank
- Drying Tower
- Water
- Air
- Fugitive Emissions
- Fugitive Emissions
- Fugitive Emissions
- Steam
- Water
- Chemical Treatment
- SWTP
- Scrap Steel
- Steel Coils
- Caustic Water
- Scrubber
- Scrubber Emissions
- Furnace Emissions
- Fugitive Emissions
Figure II-11: No. 7 Temper Mill
Figure II-12: No. 11 Coil and Shear Line

Steel Coils → Uncoiler → Crop Shear/ Side Trimmers → Mill Stand → Uncoiler → Steel Coils

Scrap Steel

Figure II-13: No. 17 Recoiler

Steel Coils → Uncoiler → Side Trimmers → Oiler → Coiler → Steel Coils

Fugitive Emissions

Coating Oil

Scrap Steel for Recycle

Used Oil to Oil Recovery
Figure II-13: Coke Oven Gas Flares

Coke Oven Gas Distribution Pipeline → Excess Coke Oven Gas Regulator → No. 1 Flare → Combustion Emissions

→ No. 2 Flare → Combustion Emissions

→ No. 3 Flare → Combustion Emissions

→ Peachtree Flare → Combustion Emissions
Figure II-14: Boilers No. 1 through No. 4
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 - Major Source

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. 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. 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.

c. “RACT Order No. 258” shall be defined as Plan Approval Order and Agreement Upon Consent Number 258, dated December 30, 1996.
3. 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.

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. 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 The required documentation and fee must be received by the Department at least 30 days before the intended transfer date.

6. Term (§2103.12.e, §2103.13.a)

a. This permit shall remain valid for five (5) years from the date of issuance, or such other shorter period if required by the Clean Air Act, unless revoked. The terms and conditions of an expired permit shall automatically continue pending issuance of a new operating permit provided the permittee has submitted a timely and complete application and paid applicable fees required under Article XXI Part C, and the Department through no fault of the permittee is unable to issue or deny a new permit before the expiration of the previous permit.

b. Expiration. Permit expiration terminates the source’s right to operate unless a timely and complete renewal application has been submitted consistent with the requirements of Article XXI Part C.

7. Need to Halt or Reduce Activity Not a Defense (§2103.12.f.2)

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

8. Property Rights (§2103.12.f.4)

This permit does not convey any property rights of any sort, or any exclusive privilege.

9. Duty to Provide Information (§2103.12.f.5)

a. The permittee shall furnish to the Department in writing within a reasonable time, any information that the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Department copies of any records required to be kept by the permit.

b. Upon cause shown by the permittee the records, reports, or information, or a particular portion
thereof, claimed by the permittee to be confidential shall be submitted to the Department in accordance with the requirements of Article XXI, §2101.07.d.4. Information submitted to the Department under a claim of confidentiality, shall be available to the US EPA and the PADEP upon request and without restriction. Upon request of the permittee the confidential information may be submitted to the USEPA and PADEP directly. Emission data or any portions of any draft, proposed, or issued permits shall not be considered confidential.

10. **Modification of Section 112(b) Pollutants which are VOCs or PM10** (§2103.12.f.7)

Except where precluded under the Clean Air Act or federal regulations promulgated under the Clean Air Act, if this permit limits the emissions of VOCs or PM$_{10}$ but does not limit the emissions of any hazardous air pollutants, the mixture of hazardous air pollutants which are VOCs or PM$_{10}$ can be modified so long as no permit emission limitations are violated. A log of all mixtures and changes shall be kept and reported to the Department with the next report required after each change.

11. **Right to Access** (§2103.12.h.2)

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized Department and other federal, state, county, and local government representatives to:

a. Enter upon the permittee's premises where a permitted source is located or an emissions-related activity is conducted, or where records are or should be kept under the conditions of the permit;

b. Have access to, copy and remove, at reasonable times, any records that must be kept under the conditions of the permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. As authorized by either Article XXI or the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements.

12. **Certification of Compliance** (§2103.12.h.5, §2103.22.i.1)

a. The permittee shall submit on an annual basis, certification of compliance with all terms and conditions contained in this permit, including emission limitations, standards, or work practices. The certification of compliance shall be made consistent with General Condition 4 above and shall include the following information at a minimum:

1) The identification of each term or condition of the permit that is the basis of the certification;

2) The compliance status;

3) Whether any noncompliance was continuous or intermittent;

4) The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with the provisions of this permit; and

5) Such other facts as the Department may require to determine the compliance status of the source.

b. All certifications of compliance must be submitted to the Department by March 31 of each year for the time period beginning January 1 of the previous year and ending December 31 of the previous year.

c. The permittee shall submit all compliance certifications to the Department. Compliance
certifications may be emailed to the Department at agreports@alleghenycounty.us, in lieu of mailing a hard copy.

13. Record Keeping Requirements (§2103.12.j.1)

a. The permittee shall maintain records of required monitoring information that include the following:

1) The date, place as defined in the permit, and time of sampling or measurements;
2) The date(s) analyses were performed;
3) The company or entity that performed the analyses;
4) The analytical techniques or methods used;
5) The results of such analyses; and
6) The operating parameters existing at the time of sampling or measurement.

b. The permittee shall maintain and make available to the Department, upon request, records, including computerized records that may be necessary to comply with the reporting and emission statements in Article XXI §2108.01.e. Such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions.

14. Retention of Records (§2103.12.j.2)

The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by 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 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 January 31 of each year for the time period beginning July 1 and ending December 31 of the previous year.
3) The next semiannual report shall be due January 31, 2017 for the time period beginning on the issuance date of this permit through December 31, 2016.
e. Quarterly reports required by this permit shall be submitted to the Department as follows:

1) One quarterly report is due by April 30 of each year for the time period beginning January 1 and ending March 31.
2) One quarterly report is due by July 31 of each year for the time period beginning April 1 and ending June 30.
3) One quarterly report is due by October 31 of each year for the time period beginning July 1 and ending September 30.
4) One quarterly report is due by January 31 of each year for the time period beginning October 1 and ending December 31 of the previous year.
5) The next quarterly report shall be due January 31, 2017 for the time period beginning on the issuance date of this permit through December 31, 2016.

f. The permittee may submit reports electronically to aqreports@alleghenycounty.us. Certification by the responsible official in accordance with condition III.4 above shall be provided separately via hand copy.


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

17. **Existing Source Reactivations (§2103.13.d)**

The permittee shall not reactivate any source that has been out of operation or production for a period of one year or more unless the permittee has submitted a reactivation plan request to, and received a written reactivation plan approval from, the Department. Existing source reactivations shall meet all requirements of Article XXI §2103.13.d.


An administrative permit amendment may be made consistent with the procedures of Article XXI §2103.14.b and §2103.24.b. Administrative permit amendments are not authorized for any amendment precluded by the Clean Air Act or the regulations thereunder.


Sources may apply for revisions and minor permit modifications on an expedited basis in accordance with Article XXI §2103.14.c and §2103.24.a.


Significant permit modifications shall meet all requirements of the applicable subparts of Article XXI, Part C, including those for applications, fees, public participation, review by affected States, and review by EPA, as they apply to permit issuance and permit renewal. The approval of a significant permit modification, if the entire permit has been reopened for review, shall commence a new full five (5) year permit term. The Department shall take final action on all such permits within nine (9) months following receipt of a complete application.
21. **Duty to Comply** (§2103.12.f.1, §2103.22.g)

The permittee shall comply with all permit conditions and all other applicable requirements at all times. Any permit noncompliance constitutes a violation of the Clean Air Act, the Air Pollution Control Act, and Article XXI and is grounds for any and all enforcement action, including, but not limited to, permit termination, revocation and reissuance, or modification, and denial of a permit renewal application.

22. **Renewals** (§2103.13.b., §2103.23.a)

Renewal of this permit is subject to the same fees and procedural requirements, including those for public participation and affected State and EPA review that apply to initial permit issuance. The application for renewal shall be submitted at least six (6) months but not more than eighteen (18) months prior to expiration of this permit. The application shall also include submission of a supplemental compliance review as required by Article XXI §2102.01.

23. **Reopenings for Cause** (§2103.15, §2103.25.a, §2103.12.f.3)

   a. This permit shall be reopened and reissued under any of the following circumstances:

      1) Additional requirements under the Clean Air Act become applicable to a major source with a remaining permit term of three (3) or more years. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended solely due to the failure of the Department to act on a permit renewal application in a timely fashion.

      2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into this permit.

      3) The Department or EPA determines that this permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

      4) The Administrator or the Department determines that this permit must be reissued or revoked to assure compliance with the applicable requirements.

   b. This permit may be modified; revoked, reopened, and reissued; or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in this permit.

24. **Reopenings for Cause by the EPA** (§2103.25.b)

This permit may be modified, reopened and reissued, revoked or terminated for cause by the EPA in accordance with procedures specified in Article XXI §2103.25.b.

25. **Annual Operating Permit Administration Fee** (§2103.40)
In each year during the term of this permit, on or before the last day of the month in which the application for this permit was submitted, the permittee shall submit to the Department, in addition to any other applicable administration fees, an Annual Operating Permit Administration Fee in accordance with §2103.40. by check or money order payable to the “Allegheny County Air Pollution Control Fund” in the amount specified in the fee schedule applicable at that time.

26. Annual Major Source Emissions Fees Requirements (§2103.41)

No later than September 1 of each year, the permittee shall pay an annual emission fee in accordance with Article XXI §2103.41 for each ton of a regulated pollutant (except for carbon monoxide) actually emitted from the source. The permittee shall not be required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant. The emission fee shall be increased in each year after 1995 by the percentage, if any, by which the Consumer Price Index for the most recent calendar year exceeds the Consumer Price Index for the previous calendar year.

27. Other Requirements not Affected (§2104.08, §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 the odor emission standards under Article XXI §2104.04, any applicable NSPSs, NESHAPs, MACTs, or Generally Achievable Control Technology (GACT) standards now or hereafter established by the EPA, and any applicable requirements of BACT or LAER as provided by Article XXI, any condition contained in any applicable Installation or Operating Permit and/or any additional or more stringent requirements contained in an order issued to such person pursuant to Article XXI Part I.

28. Termination of Operation (§2108.01.a)

In the event that operation of any source of air contaminants is permanently terminated, the person responsible for such source shall so report, in writing, to the Department within 60 days of such termination.

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

a. Emissions inventory statements in accordance with Article XXI §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.

30. Tests by the Department (§2108.02.d)

Notwithstanding any tests conducted pursuant to Article XXI §2108.02, 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 person responsible for such source or equipment shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.
31. **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.

32. **Enforcement and Emergency Orders** (§2109.03, §2109.05)

a. The person responsible for this source shall be subject to any and all enforcement and emergency orders issued to it by the Department in accordance with Article XXI §2109.03, §2109.04 and §2109.05

b. Upon request, any person aggrieved by an Enforcement Order or Emergency Order shall be granted a hearing as provided by Article XXI §2109.03.d; provided, however, that an Emergency Order shall continue in full force and effect notwithstanding the pendency of any and such appeal

c. Failure to comply with an Enforcement Order or immediately comply with an Emergency Order shall be a violation of this permit, thus giving rise to the remedies provided by Article XXI §2109.02.

33. **Penalties, Fines, and Interest** (§2109.07.a)

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

34. **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 or any unsuccessful petitioner to the Administrator under Article XXI Part C, Subpart 2, shall have the right to appeal the action to the Director in accordance with the applicable County regulations and ordinances.

35. **Risk Management** (§2104.08, 40 CFR Part 68)

Should this stationary source, as defined in 40 CFR Part 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in Part 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by *General Condition III.12* above.

36. **Permit Shield** (§2103.22)

a. The permittee’s compliance with the conditions of this permit shall be deemed compliance with all major source applicable requirements as of the date of permit issuance, provided that:

1) Such major source applicable requirements are included and are specifically identified in the permit; or
2) The Department, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

b. Nothing in Article XXI §2103.22.e or the Title V Permit shall alter or affect the following:

1) The provisions of Section 303 of the Clean Air Act and the provisions of Article XXI regarding emergency orders, including the authority of the Administrator and the Department under such provisions;
2) The liability of any person who owns, operates, or allows to be operated, a source in violation of any major source applicable requirements prior to or at the time of permit issuance;
3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; or
4) The ability of the EPA or the County to obtain information from the permittee pursuant to Section 114 of the Clean Air Act, the provisions of Article XXI and State law.

c. Unless precluded by the Clean Air Act or regulations therein, final action by the Department on administrative amendments, minor and significant permit modifications, and operational flexibility changes shall be covered by the permit shield provided such amendments, modifications and changes meet the relevant requirements of Article XXI.

d. The permit shield authorized under Article XXI §2103.22 is in effect for the permit terms and conditions as identified in this permit.

37. **Circumvention (§2101.14)**

For purposes of determining compliance with the provisions of this permit and Article XXI, no credit shall be given to any person for any device or technique, including but not limited to the operation of any source with unnecessary amounts of air, the combining of separate sources except as specifically permitted by Article XXI and the Department, the use of stacks exceeding Good Engineering Practice height as defined by regulations promulgated by the US EPA at 40 CFR §§51.100 and 51.110 and Subpart I, and other dispersion techniques, which without reducing the amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise violate the provisions of this Article; except that, for purposes of determining compliance with Article §2104.04 concerning odors, credit for such devices or techniques, except for the use of a masking agent, may be given.

38. **Duty to Supplement and Correct Relevant Facts (§2103.12.d.2)**

a. The permittee shall provide additional information as necessary to address the requirements that become applicable to the source after the date it files a complete application but prior to the Department taking action on the permit application.

b. The permittee shall provide supplementary fact or corrected information upon becoming aware that incorrect information has been submitted or relevant facts were not submitted.

c. Except as otherwise required by this permit and Article XXI, the Clean Air Act, or the regulations thereunder, the permittee shall submit additional information as necessary to address changes occurring at the source after the date it files a complete application but prior to the Department taking action on the permit application.
d. The applicant shall submit information requested by the Department which is reasonably necessary to evaluate the permit application.

39. Effect (§2102.03.g.)

a. Except as specifically otherwise provided under Article XXI, Part C, issuance of a permit pursuant to Article XXI Part B or Part C shall not in any manner relieve any person of the duty to fully comply with the requirements of this permit, 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 this permit or Article XXI, whether occurring before or after the issuance of such permit. Further, except as specifically otherwise provided under Article XXI Part C the issuance of a 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 this permit or Article XXI.

40. Installation Permits (§2102.04.a.1.)

It shall be a violation of this permit giving rise to the remedies set forth in Article XXI Part I for any person to install, modify, replace, reconstruct, or reactivate any source or air pollution control equipment which would require an installation permit or permit modification in accordance with Article XXI Part B or Part C.

**PERMIT SHIELD IN EFFECT**
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. 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) The 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.

8. 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.

9. Emissions Inventory Statements (§2108.01.e)

The permittee shall submit to the Department a written emissions inventory statement, in accordance with §2108.01.e, showing the actual emissions of all regulated air pollutants from such source(s) during each calendar year and all supporting and identifying information deemed necessary by the Department.

10. Orders (§2108.01.f)

In addition to meeting the requirements of General Condition III.28 and Site Level Conditions IV.7 through IV.9 above, inclusive, and IV.16 below, 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.

11. Violations (§2108.01.g)

The failure to submit any report or update thereof required by General Condition III.28 and Site Level Conditions IV.7 through IV.10 above, inclusive, and IV.16 below 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. Emissions Testing (§2108.02)

a. On or before December 31, 1981, and at two-year intervals thereafter, any person who operates, or allows to be operated, any piece of equipment or process which has an allowable emission rate, of 100 or more tons per year of particulate matter, sulfur oxides or volatile organic compounds shall conduct, or cause to be conducted, for such equipment or process such emissions tests as are necessary to demonstrate compliance with the applicable emission limitation(s) of this permit and shall submit the results of such tests to the Department in writing. Emissions testing conducted pursuant to this section shall comply with all applicable requirements of Article XXI §2108.02.e.

b. Orders. In addition to meeting the requirements of Site Level Condition IV.12.a above, the person responsible for any source shall, upon order by the Department, conduct, or cause to be conducted, such emissions tests as specified by the Department within such reasonable time as is specified by the Department. Test results shall be submitted in writing to the Department within 20 days after completion of the tests, unless a different period is specified in the Department's order. Emissions testing shall comply with all applicable requirements of Article XXI §2108.02.e.
c. **Tests by the Department.** Notwithstanding any tests conducted pursuant to Site Level Conditions IV.12.a and IV.12.b above, 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 person responsible for such source or equipment shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.

d. **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.

e. 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.

f. **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.

13. **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.


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. In the event of demolition or renovation of asbestos, the permittee shall comply with all applicable provisions of 40 CFR 61.145 and 40 CFR 61.150.

15. **Protection of Stratospheric Ozone (40 CFR Part 82)**
a. Permittee shall comply with the standards for labeling of products using ozone-depleting substances pursuant to 40 CFR Part 82, Subpart E:

1) All containers in which a Class I or Class II substance is stored or transported, all products containing a Class I substance, and all products directly manufactured with a process that uses a Class I substance must bear the required warning statement if it is being introduced into interstate commerce pursuant to §82.106;

2) The placement of the required warning statement must comply with the requirements pursuant to §82.108;

3) The form of the label bearing the required warning statement must comply with the requirements pursuant to §82.110; and

4) No person may modify, remove or interfere with the required warning statement except as described in §82.112.

b. Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F:

1) Persons opening appliances for maintenance, service, repair or disposal must comply with the prohibitions and required practices pursuant to §82.154 and §82.156;

2) Equipment used during the maintenance, service, repair or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158;

3) Persons maintaining, servicing, repairing or disposing of appliances, must be certified by an approved technician certification program pursuant to §82.161;

4) Persons maintaining, servicing, repairing or disposing of appliances must certify to the Administrator of the U.S. Environmental Protection Agency pursuant to §82.162;

5) Persons disposing of small appliances, motor vehicle air conditioners (MVAC) and MVAC-like appliances, must comply with the record keeping requirements pursuant to §82.166;

6) Owners of commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156; and

7) Owners or operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

c. If the permittee manufactures, transforms, destroys, imports or exports a Class I or Class II substance, the permittee is subject to all the requirements as specified in 40 CFR Part 82, Subpart A (Production and Consumption Controls).

d. If the permittee performs a service on a motor vehicle that involves an ozone-depleting substance, refrigerant or regulated substitute substance in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B (Servicing of Motor Vehicle Air Conditioners).
e. If the permittee has containers or products containing or manufactured with certain ozone-depleting substances, the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart E (The Labeling of Products Using Ozone-Depleting Substances).

f. If the permittee services, performs maintenance or repairs, or disposes of appliances that contain class I or class II refrigerants, the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart F (Recycling and Emissions Reduction).

g. The permittee may switch from any ozone-depleting substance to any alternative that is listed as acceptable in the Significant New Alternatives Policy (SNAP) program promulgated pursuant to 40 CFR Part 82, Subpart G.

h. If the permittee tests, services, maintains, repairs, or disposes of equipment that contains halons or uses such equipment during technician training, the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart H (Halon Emissions Reduction)

16. 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.16.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) The 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;

i. 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
ii. Such other information as may be required by the Department.

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. 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. Notwithstanding any other provisions of this permit, the prohibitions of Site Level Condition IV.22 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.22.
23. **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.

24. **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.


The provisions of 40 CFR 63, Subpart DDDDD, which are incorporated by reference in ACHD Article XXI §2104.08.a, apply to the 4 boilers; HPH Batch Annealing Furnaces (31 individual furnaces); Open Coil Annealing Furnaces (16 furnaces); Continuous Annealing, and No.1 Continuous Galvanizing Galvaneal Furnace. The permittee shall comply with the emissions limitation, testing, monitoring, recordkeeping, reporting and workpractice standards. The facility shall submit an application to Department within 6 months of the compliance date January 31, 2016 to incorporate specific requirements from 40 CFR 63, Subpart DDDDD in accordance with §2103.25.a.1. [§2103.12.h.6; §2103.12.f.3; §2103.25.a.1; §63.7495.b.]

26. **SO₂ Compliance Monitoring (SO₂ SIP IP 0050-1008, Condition IV.25)**

a. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted as a fuel for or at any source 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. (§2105.21.h)

b. For the sources V.A, V.E, V.F, V.G, V.K V.L V.M and V.N, the permittee shall determine the H₂S grain loading and flow rate of the fuel as combusted. The permittee shall record the output of each system for measuring sulfur dioxide emissions discharged to the atmosphere.

c. SO₂ emissions from Boilers No. 3 & 4 (aggregate) shall not exceed the limitations in Table V-L-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]
TABLE IV-1
SO₂ Emission Limitations for Boilers 3 & 4

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.21</td>
<td>9.30</td>
<td>35.96</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

27. The Continuous Terne Line (P014), and Galvaneal Furnace (part of P012) have been removed from the permit. They are no longer in operation, and shall not be operated.

PERMIT SHIELD IN EFFECT
V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Process P001: 80-inch Hot Strip Mill

Process Description: 80” Hot Strip Mill Reheat Furnaces, Roughing and Finishing Mills
Facility ID: P001 – P005 and P016
Max. Design Rate: 140 mmBtu/hr maximum heat input, each reheat furnace
Capacity: 3,000,000 tons of sheets per year
Raw Materials: Steel Slabs, Natural Gas and Coke Oven Gas
Control Device: None

As identified above, the 80” Hot Strip Mill includes five reheat furnaces (P001 – P005) and the roughing and finishing mills (P016).

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in reheat furnaces No. 1 through No. 5. [§2103.12.h.5.D]

b. The permittee shall not operate or, allow to be operated reheat furnaces No. 1 through No. 5 such a manner that the emissions of particulate matter exceeds 7 pounds in any 60 minute period or 100 pounds in any 24-hour period [§2104.02.b]

c. The permittee shall not operate or, allow to be operated the scale breaking/roughing and finishing mill stands in such a manner that the emissions of particulate matter exceeds 7 pounds in any 60 minute period or 100 pounds in any 24-hour period [§2104.02.b]

d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in reheat furnaces No. 1 through No. 5, 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. [§2105.21.h.4]

e. The permittee shall operate the 80” Hot Strip Mill scale breaking/roughing and finishing mill stands with lubricating oil, which is an oil-water emulsion and does not exceed a maximum VOC content by weight, of 1%, at any time. [RACT Order No. 258; §2105.06; 25 PA Code §129.99]

f. Emissions from the Hot Strip Mill Reheat Furnaces No. 1 through No. 5 shall not exceed the emission limitations in Table V-A-1. [§2104.02; §2104.03; §2101.02.c.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Coke Oven Gas (lb/hr)</th>
<th>Natural Gas (lb/hr)</th>
<th>Annual Emission Limit (tons/year)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM-10</td>
<td>7.0</td>
<td>7.0</td>
<td>18.25</td>
</tr>
</tbody>
</table>

*A year is defined as any consecutive 12-month period.*
g. SO₂ emissions from the Hot Strip Mill Reheat Furnaces (aggregate) shall not exceed the
limitations in Table V-A-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>108.63</td>
<td>118.75</td>
<td>475.80</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

** Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:

a. The permittee shall have sulfur dioxide (SO₂) emissions tests performed on the stacks of reheat furnaces No. 1 through No. 5 at least once every two years to demonstrate compliance with the mass emission limitations for the reheat furnaces No. 2 through No. 5 in condition V.A.1.g above. The test shall be conducted according to Method 6, 6A, 6B, or 6B specified in 40 CFR 60, Appendix A, and as approved by the Department. The permittee shall submit a stack test protocol to the Department for approval at least 45 days prior to the test dates. [SO₂ SIP IP 0050-1008, Condition V.A.2.a; §2108.02.b & .e]

b. The permittee shall perform emissions tests and evaluations for NOₓ, CO, and VOC on the stacks of reheat furnaces No. 1 through No. 5 to develop emission factors that can be applied to quantify NOₓ, CO, and VOC emissions. Testing for NOₓ, CO, and VOCs shall be conducted in accordance with approved EPA Methods in Appendix A of 40 CFR 60, Article XXI §2108.02, and as approved by the Department. Reports of the evaluation and stack testing results shall be submitted to the Department within 90 days of the date of the stack test. If testing results indicate emissions in excess of the thresholds identified in §2108.02.b, testing shall be conducted biennially for the applicable pollutant.

c. 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 12 entitled “Emissions Testing.” (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Condition IV.26.b above. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.A.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.A.3.a. However, if there is a change to the current operating
scenario, the sulfur concentration will be taken at the Irvin Plant. (§2103.12.h.5.B)

4. **Record Keeping Requirements:**
   a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No. 258; 25 PA Code §129.100]
      1) The date of the annual tune-up;
      2) The name of the service company and/or individuals performing the annual tune-up;
      3) The operating rate or load after the annual tune-up; and
      4) The CO and NOₓ emission rate before and after the annual tune-up
   b. The permittee shall maintain hourly, monthly and 12 month rolling totals of the fuel type (COG & natural gas), and fuel usage and hourly H₂S concentration expressed in grains per 100 dscf for each 80" Hot Strip Mill reheat furnace. [§2103.12.h.5.B; §2103.12.j; SIP IP 0050-1008, Condition V.A.4.a; 25 PA Code §129.100]
   c. The permittee shall maintain sufficient documentation to demonstrate compliance with the VOC requirements in RACT Order No. 258 for the 80" Hot Strip Mill. Compliance with this RACT requirement may be demonstrated by documentation from all suppliers of oils for the 80" Hot Strip Mill that includes the VOC content of these oils. [§2103.12.j, 25 PA Code §129.100]
   d. 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, 25 PA Code §129.100]

5. **Reporting Requirements:**
   a. The permittee shall provide semi-annual reports, as specified in Condition III.15 above, of the type and amount of each fuel combusted in the reheat furnaces required by Condition V.A.4.a. [§2103.12.k]
   b. The permittee shall report the concentration of H₂S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [§2103.12.k; §2103.12.j; SIP IP 0050-1008, Condition V.A.5.a]
   c. Reporting instances of non-compliance in accordance with Condition V.A.5.b above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. **Work Practice Standards:**
   a. The permittee shall perform an annual adjustment or "tune-up" on each furnace once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No. 258; 25 PA Code §129.99]
      1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
      2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total
emissions of NO\(_x\), and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
B. Process P002: 64” Continuous Coil HCl Pickle Line

**Process Description:** The pickle line consists of steel roll uncoilers, four (4) hydrochloric acid pickling tanks in series, a rinse tank, a dryer, a coiler and hydrochloric acid storage tanks.

**Facility ID:** P002

**Max. Design Rate:** 1,047,174 tons of sheets per year

**Capacity:** 1,047,174 tons of sheets per year

**Raw Materials:** Steel coils, HCl pickle liquor

**Control Device:** HCl Scrubber

As identified above, Process P002 consists of the following number and type of equipment: steel roll uncoilers, four hydrochloric acid pickling tanks in series, a dryer and a coiler.

1. Restrictions - Installation Permits, Standards for Issuance, BACT

   a. The permittee shall not operate or allow to be operated the 64” continuous coil HCl pickle line unless the four hydrochloric acid pickling tanks and the rinse tank, are equipped with an acid mist capture system that exhausts to a water wash packed tower scrubbing system. The collection and scrubbing system shall be properly maintained and operated, controlling hydrochloric acid emissions from the pickle line, according to the following specifications while the line is in operation: [Installation Permit No. 0050-I001b, Condition V.A.1.a, §2103.12.a.2.B and §2102.04.b.6]

   1) The acid mist capture system shall have a slight negative air flow into the system at all times and cover the acid and rinse tanks completely with minimum openings for the steel sheet inlet and outlet and associated piping.

   2) The water washed packed tower scrubber shall have the minimum scrubber makeup water and recirculating water flow rates determined by the average of the values recorded during the initial and/or subsequent scrubber emission testing as specified in Conditions V.B.2.a and V.B.2.b below.

   b. The permittee shall not cause or allow to be discharged into the atmosphere from the pickling line: [IP No. 0050-I001b, Condition V.A.1.b §63.1158(a); §2102.04.b.6]

   1) Any gases that contain HCl in a concentration in excess of 6 parts per million by volume (ppmv); and

   2) HCl at a mass emission rate that corresponds to a collection efficiency of less than 99 percent.

   c. The pickle line wet scrubber and HCl storage tank scrubber exhausts are subject to opacity requirements in Site Level Condition IV.2 above. [IP No. 0050-I001b, Condition V.A.1.c; §2104.01.a]

   d. The permittee of a hydrochloric acid storage vessel(s) shall provide and operate, except during loading and unloading of acid, a closed-vent system for each vessel. Loading and unloading shall be conducted either through enclosed lines or each point where the acid is exposed to the atmosphere shall be equipped with a local fume capture system, ventilated through an air pollution control device. The HCl fume scrubber shall be in place and operating according to the following specifications while in operation: [IP No. 0050-I001b, Condition V.A.1.d; §63.1159(b)]

   1) Packed tower HCl fume scrubber minimum scrubbing liquid flow rate of 11 gallons per minute.
2) Instrumentation shall be provided to measure the scrubbing liquid flow rate at any time, to within 5% of actual flow rate. Calibrations shall be performed semiannually.

e. The permittee shall comply with the operation and maintenance requirements prescribed under §63.6(e) of 40 CFR Part 63, Subpart A. [IP No. 0050-I001b, Condition V.A.1.f; §63.1160(b)(1)]

f. The permittee shall at no time, operate or allow to be operated, the tension leveler/scale breaker unless it is enclosed with all particulate emissions exhausted to the tension leveler/scale breaker dust collector. The dust collector shall be in place and operating, treating all particulate matter emissions from the tension leveler/scale breaker according to the following specifications while in operation. [Installation Permit No. 0050-I001b, Condition V.A.1.g and §2102.04.b.6]

   1) Tension leveler/scale breaker dust collector – minimum and maximum pressure drop across the dust collector equal to 0.5 and 8.0 inches of water column, gauge.

g. Emissions from the Tension Leveler/Scale Breaker Dust Collector (SP023) shall not exceed the emission limitations in Table V-B-1 at any time. [IP No. 0050-I001b, Condition V.A.1.h; §2102.04.b.6; §2103.12.g]:

   Table V-B-1 - Tension Leveler/Scale Breaker Dust Collector Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.02</td>
<td>0.09</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.02</td>
<td>0.09</td>
</tr>
</tbody>
</table>

  ¹ A year is defined as any 12 consecutive months.

h. Emissions from the 64” continuous coil pickle line shall not exceed the emission limitations in Table V-B-2 at any time. [IP No. 0050-I001b, Condition V.A.1.i; §63.1158(a); §2102.04.b.6; §2103.12.g]

   Table V-B-2 - 64” Continuous Coil HCl Pickle Line Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Hourly Emission lbs/hr</th>
<th>Annual Emission tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.41</td>
<td>1.79</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.41</td>
<td>1.79</td>
</tr>
<tr>
<td>HCl</td>
<td>0.41</td>
<td>1.79</td>
</tr>
</tbody>
</table>

  ¹ A year is defined as any 12 consecutive months.

i. Compliance with the hydrochloric acid emission limitations for the 64” Continuous Coil HCl Pickle Line in Condition V.B.1.h above, shall be determined by initial and subsequent HCl emission testing annually as specified in Condition V.B.2.a below. Compliance with the particulate emission limitation for the wet scrubber shall be determined by assuming all hydrochloric acid emissions are PM-10 emissions. [Installation Permit No. 0050-I001b, Condition V.A.1.j and §2105.03]

2. Testing Requirements

   a. The permittee shall conduct a performance test for each process or emission control device to
determine and demonstrate compliance with the applicable emission limitation according to the requirements in §63.7 of 40 CFR 63, Subpart A. [IP No. 0050-I001b, Condition V.A.2.a; §63.1161(a) and §2102.04.b.6]

1) Following approval of the site-specific test plan, the permittee shall conduct a performance test of the 64" continuous coil HCl pickle line wet scrubber control device to measure simultaneously the mass flows of HCl at the inlet and the outlet of the control device (to determine compliance with the applicable collection efficiency standard) and measure the concentration of HCl in gases exiting the process or the emission control device. [§63.1161(a)(1)]

2) Compliance with the applicable concentration standard and collection efficiency standard shall be determined by the average of three consecutive runs or by the average of any three of four consecutive runs. Each run shall be conducted under conditions representative of normal process operations. (§63.1161(a)(2))

3) Compliance with V.B.1.b above is achieved if the average collection efficiency as determined by the HCl mass flows at the control device inlet and outlet is greater than or equal to the applicable collection efficiency standard, and the average measured concentration of HCl exiting the emission control device is less than or equal to the applicable emission concentration standard. (§63.1161(a)(3))

b. During the performance test for the wet scrubber emission control device, the permittee using a wet scrubber to achieve compliance shall establish site-specific operating parameter values for the minimum scrubber makeup water flow rate and, for a scrubber that operates with recirculation, the minimum recirculation water flow rate. During the emission test, each operating parameter must be monitored continuously and recorded with sufficient frequency to establish a representative average value for that parameter, but no less frequently than once every 15 minutes. The permittee shall determine the operating parameter monitoring values as the averages of the values recorded during any of the runs for which results are used to establish the emission concentration and the collection efficiency per Condition V.B.1.b above. The permittee may conduct multiple performance tests to establish alternative compliant operating parameter values. Also, the permittee may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests. [IP No. 0050-I001b, Condition V.A.2.b; §63.1161(b)]

c. The permittee shall notify the Department in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, to allow the Department to review and approve the site-specific test plan required under Subpart A of 40 CFR 63.7(c) and, if requested by the Department, to have an observer present during the test. [IP No. 0050-I001b, Condition V.A.2.c; §63.1163(d)]

d. The permittee shall conduct performance tests to measure the HCl mass flows at the control device inlet and outlet and the concentration of HCl exiting the control device according to the procedures described in Condition V.B.2.a above. Performance tests to measure the HCl mass flows at the control device inlet and outlet shall be conducted at least once every five years. Performance tests to measure the concentration of HCl exiting the control device shall be conducted either annually or according to an alternative schedule that is approved by the Department, but no less frequently than every 2 1/2 years or twice per title V permit term. If any performance test shows that the HCl emission limitation is being exceeded, then the permittee is in violation of the emission limit. [Installation Permit No. 0050-I001b, Condition V.A.2.d; §63.1162(a) and §2108.02.b]
e. The following test methods in Appendix A of 40 CFR Part 60 shall be used to determine compliance with Condition V.B.1.b above: [IP No. 0050-I001b, Condition V.A.2.e §63.1161(d)]

1) Method 1, to determine the number and location of sampling points, with the exception that no traverse point shall be within one inch of the stack or duct wall;

2) Method 2, to determine gas velocity and volumetric flow rate;

3) Method 3, to determine the molecular weight of the stack gas;

4) Method 4, to determine the moisture content of the stack gas; and

5) Method 26A, "Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources -- Isokinetic Method," to determine the HCl mass flows at the inlet and outlet of a control device or the concentration of HCl discharged to the atmosphere. If compliance with a collection efficiency standard is being demonstrated, inlet and outlet measurements shall be performed simultaneously. The minimum sampling time for each run shall be 60 minutes and the minimum sample volume 0.85 dry standard cubic meters (30 dry standard cubic feet). The concentrations of HCl and Cl2 shall be calculated for each run as follows:

$$C_{HCl}(\text{ppmv}) = 0.659 \times C_{HCl}(\text{mg/dscm}),$$

Where C(ppmv) is concentration in ppmv and C(mg/dscm) is concentration in milligrams per dry standard cubic meter as calculated by the procedure given in Method 26A.

g. The Department reserves the right to require emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with §2108.02. (IP No. 0050-I001b, Condition V.A.2.g; §2103.12.h.1)

3. Monitoring Requirements

a. The tension leveler/scale breaker dust collector shall be provided with instrumentation to continuously monitor the pressure drop across the dust collector, when treating particulate emissions from the tension leveler/scale breaker. [IP No. 0050-I001b, Condition V.A.3.a]

b. If the pressure drop exceeds the normal range as specified in V.B.1.f.1) above, the permittee shall initiate an investigation and implement corrective action. Operation outside the pressure drop range shall not be considered a deviation if corrective action is taken in 7 days. [IP No. 0050-I001b, Condition V.A.3.b; §2102.04.b.6]

c. The permittee shall inspect the tension leveler/scale breaker dust collector on a weekly basis to insure compliance with Conditions V.B.1.f and V.B.3.a above. Any excursions from these conditions shall be corrected as soon as possible. [IP No. 0050-I001b, Condition V.A.3.c; §2102.04.b.6]

d. The water wash packed tower scrubber shall be provided with instrumentation that shall monitor the pressure drop across the scrubber once per shift. [IP No. 0050-I001b, Condition V.A.3.d; §63.1160(b)(2)(i) and §2102.04.b.6]

e. The permittee shall install, operate, and maintain systems for the measurement and recording of the scrubber makeup water flow rate, and recirculation water flow rate. These flow rates must be
monitored continuously and recorded at least once per shift while the scrubber is operating. Operation of the wet scrubber with excursions of scrubber makeup water flow rate and recirculation water flow rate less than the minimum values established during the performance test or tests will require initiation of corrective action as specified by the maintenance requirements in V.B.6.a below. [IP No. 0050-I001b, Condition V.A.3.e; §63.1162(a)(2)]

4. Record Keeping Requirements

a. The results of inspections required by Condition V.B.3.c above, and the differential pressure drop across the tension leveler/scale breaker dust collector, shall be recorded weekly. Episodes of noncompliance with Conditions V.B.1.f and V.B.3.a above and corrective action taken shall be recorded upon occurrence. All records shall be kept on a monthly basis. [IP No. 0050-I001b, Condition V.A.4.a; §2102.04.b.6]

b. The results of inspections required by Condition V.B.3.i above shall be recorded upon each occurrence. Episodes of noncompliance with Conditions V.B.1.d above and corrective action taken shall be recorded upon occurrence. All records shall be kept on a semiannual basis. [IP No. 0050-I001b, Condition V.A.4.b; §2102.04.b.6]

c. The permittee shall maintain a record of each inspection, including each item identified in paragraph V.B.6.a.4) below, that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other corrective action taken. [IP No. 0050-I001b, Condition V.A.4.c; §63.1160(b)(2)(vii)]

d. As required by §63.10(b)(2), the permittee shall maintain records for 5 years from the date of each record of: [IP No. 0050-I001b, Condition V.A.4.d; §63.1165(a)]

1) The occurrence and duration of each startup, shutdown, or malfunction of operation (i.e., process equipment);
2) The occurrence and duration of each malfunction of the air pollution control equipment;
3) All maintenance performed on the air pollution control equipment;
4) Actions taken during periods of startup, shutdown, and malfunction and the dates of such actions (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) when these actions are different from the procedures specified in the startup, shutdown, and malfunction plan;
5) All information necessary to demonstrate conformance with the startup, shutdown, and
malfunction plan when all actions taken during periods of startup, shutdown, and malfunction (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. This information can be recorded in a checklist or similar form [see 40 CFR 63.10(b)(2)(v)];

6) All required measurements needed to demonstrate compliance with the standard and to support data that the permittee is required to report, including, but not limited to, performance test measurements (including initial and any subsequent performance tests) and measurements as may be necessary to determine the conditions of the initial test or subsequent tests;

7) All results of initial or subsequent performance tests;

8) All documentation supporting initial notifications and notifications of compliance status required by 40 CFR 63.9; and

9) Records of any applicability determination, including supporting analyses.

e. In addition to the general records required by paragraph V.B.4.d above, the permittee shall maintain records for 5 years from the date of each record of: [IP No. 0050-I001b, Condition V.A.4.e;§63.1165(b)(1); §2103.12.j]

1) Scrubber makeup water flow rate and recirculation water flow rate;

2) Calibration and manufacturer certification that monitoring devices are accurate to within 5 percent; and

3) Each maintenance inspection and repair, replacement, or other corrective action.

f. The permittee shall record the production and hours of operation of the 64” continuous coil HCl pickle line on a daily basis, and the monthly throughput of HCl for each storage tank. [IP No. 0050-I001b, Condition V.A.4.f;§2103.12.j]

g. The pressure drop across the scrubber shall be recorded at least once daily and during the initial and/or subsequent scrubber emission testing. (IP No. 0050-I001b, Condition V.A.1.a.3; §2102.04.b.6; §2103.12.j]

h. The permittee shall keep the written operation and maintenance plan on record after it is developed to be made available for inspection, upon request, by the Department for the life of the affected source or until the source is no longer subject to these provisions. In addition, if the operation and maintenance plan is revised, the permittee shall keep previous (i.e., superseded) versions of the plan on record to be made available for inspection by the Department for a period of 5 years after each revision to the plan. [IP No. 0050-I001b, Condition V.A.4.g; §63.1165(b)(3)]

i. Records for the most recent 2 years of operation must be maintained on site. Records for the previous 3 years may be maintained off site. [IP No. 0050-I001b, Condition V.A.4.h;§63.1165(c)]

5. Reporting Requirements

a. The permittee shall submit a notification of compliance status as required by 40 CFR 63.9(h). [IP No. 0050-I001b, Condition V.A.5.a; §63.1163(e)]

b. The permittee shall report the results of any performance test required in paragraph V.B.2.a and V.B.2.d above. [IP No. 0050-I001b, Condition V.A.5.b; §63.1164(a)]

c. As required by 40 CFR §63.10(d)(5)(i), if actions taken by the permittee during a startup, shutdown, or malfunction of the 64” continuous coil pickle line (including actions taken to correct a malfunction) are consistent with the procedures specified in the startup, shutdown, and malfunction
EMISSION UNIT LEVEL TERMS AND CONDITIONS

U. S. Steel Mon Valley Works – Irvin Plant
Title V Operating Permit No. 0050-OP16b

plan, the permittee shall state such information in a semiannual report. The report, to be certified by the permittee or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half. [IP No. 0050-I001b, Condition V.A.5.c; §63.1164(c)(2)]

d. Any time an action taken by the permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures in the startup, shutdown, and malfunction plan, the permittee shall comply with all requirements of 40 CFR 63.10(d)(5)(ii). [IP No. 0050-I001b, Condition V.A.5.d; §63.1164(c)(3)]

e. Reporting instances of non-compliance in accordance with condition V.B.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. (IP No. 0050-I001b, Condition V.A.5.e; §2103.12.k.1)

6. Work Practice Standard (§2102.04.b.6)

a. In addition to the requirements specified in paragraph V.B.1.e above, the permittee shall prepare an operation and maintenance plan for the 64” continuous coil HCl pickle line scrubber emission control devices. The plan shall be submitted to the Department for approval. The plan must be consistent with good maintenance practices and, for a scrubber emission control device, must at a minimum: [IP No. 0050-I001b, Condition V.A.6.a; §63.1160(b)(2) and §2102.04.b.6]

1) Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;
2) Require the manufacturer’s recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system;
3) Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;
4) Require an inspection of each scrubber at intervals of no less than 3 months with:
   a) Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;
   b) Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;
   c) Repair or replacement of droplet eliminator elements as needed;
   d) Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and
   e) Adjustment of damper settings for consistency with the required air flow.
5) If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Department may be used.
6) The permittee shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirements of this permit.

b. The permittee shall operate and maintain the 64” continuous coil HCl pickle line and the wet scrubber emission control device, in a manner consistent with good air pollution control practices for minimizing emissions at least to the level required by paragraph V.B.1.b above at all times, including during any period of startup, shutdown, or malfunction. Malfunctions must be corrected as soon as practicable after their occurrence in accordance with the startup, shutdown, and
malfunction plan specified in paragraph V.B.6.c below. [IP No. 0050-I001b, Condition V.A.6.b; §63.1164(c)]

c. As required by §63.6(e)(3) of 40 CFR Part 63, Subpart A, the permittee shall develop and implement a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the 64” continuous coil HCl pickle line and the wet scrubber emission control device during periods of startup, shutdown, or malfunction, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with the emission limitations in paragraph V.B.1.b above. [IP No. 0050-I001b, Condition V.A.6.c; §63.1164(c)(1)]

7. **Additional Requirements**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
C. Process P007: 84" Continuous Pickle Line

Process Description: The pickle line consists of steel roll uncoilers, 4 hydrochloric acid pickling tanks in series, a rinse tank, a dryer and a coiler.

Facility ID: P007
Max. Design Rate: 1,576,800 tons of sheet per year
Capacity: 1,576,800 tons of sheet per year
Raw Materials: Steel coils, HCl pickle liquor
Control Device: HCl Scrubber

As identified above, Process P007 consists of the following number and type of equipment: steel roll uncoilers, four hydrochloric acid pickling tanks in series, a dryer and a coiler.

1. Restrictions: - Installation Permits, Standards for Issuance, BACT

   a. The permittee shall not operate or allow to be operated the 84" continuous coil HCl pickle line unless the four hydrochloric acid pickling tanks and the rinse tank are equipped with an acid mist capture system that exhausts to a water wash scrubbing system. The collection and scrubbing system shall be properly maintained and operated, controlling hydrochloric acid emissions from the pickle line. [§2102.04.b.5]

   b. The permittee shall not cause or allow to be discharged into the atmosphere from the 84" continuous pickling line scrubber: [§63.1157(a)]

      1) Any gases that contain HCl in a concentration in excess of 18 parts per million by volume (ppmv); or
      2) HCl at a mass emission rate that corresponds to a collection efficiency of less than 97 percent.

   c. The pickle line wet scrubber exhaust is subject to the opacity requirements in Site Level Condition IV.2. [§2104.01.a]

   d. The permittee shall comply with the operation and maintenance requirements prescribed under paragraph 63.6(e) of 40 CFR Part 63, Subpart A. [§63.1160(b)(1)]

   e. Emissions from the 84" Continuous Coil HCl Pickle Line shall not exceed the emission limitations in Table V-C at any time. [§63.1157(a)(1) and §2102.04.b.5]:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Hourly Emission Limit lbs/hr</th>
<th>Annual Emission Limit tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCl</td>
<td>2.9</td>
<td>12.55</td>
</tr>
</tbody>
</table>

   ¹ A year is defined as any 12 consecutive months.

2. Testing Requirements:

   a. The permittee shall conduct a performance test for each process or emission control device to determine and demonstrate compliance with the emission limitation in Condition V.C.1.b above, according to the requirements in §63.7 of 40 CFR Part 63, Subpart A. The testing shall be completed as follows: [§63.1161(a)]

      1) Following approval of the site-specific test plan, the permittee shall conduct a performance test
of the 84” continuous coil HCl pickle line wet scrubber control device to either measure simultaneously the mass flows of HCl at the inlet and the outlet of the control device (to determine compliance with the collection efficiency standard of 97 percent) or measure the concentration of HCl in gases exiting the process or the emission control device (to determine compliance with the emission concentration standard of 18 ppmv). [§63.1161(a)(1)]

2) Compliance with the applicable concentration standard or collection efficiency standard shall be determined by the average of three consecutive runs or by the average of any three of four consecutive runs. Each run shall be conducted under conditions representative of normal process operations. [§63.1161(a)(2)]

3) Compliance is achieved if either the average collection efficiency as determined by the HCl mass flows at the control device inlet and outlet is greater than or equal to the applicable collection efficiency standard, or the average measured concentration of HCl exiting the emission control device is less than or equal to the applicable emission concentration standard. [§63.1161(a)(3)]

b. During the performance test for the wet scrubber emission control device, the permittee using a wet scrubber to achieve compliance shall establish site-specific operating parameter values for the minimum scrubber makeup water flow rate and, for a scrubber that operates with recirculation, the minimum recirculation water flow rate. During the emission test, each operating parameter must be monitored continuously and recorded with sufficient frequency to establish a representative average value for that parameter, but no less frequently than once every 15 minutes. The permittee shall determine the operating parameter monitoring values as the averages of the values recorded during any of the runs for which results are used to establish the emission concentration and the collection efficiency per Condition V.C.1.b above. The permittee may conduct multiple performance tests to establish alternative compliant operating parameter values. Also, the permittee may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests. [§63.1161(b)]

c. The permittee shall notify the Department in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, to allow the Department to review and approve the site-specific test plan required under Subpart A of 40 CFR 63.7(c) and, if requested by the Department, to have an observer present during the test. [§63.1163(d)]

d. The permittee shall conduct performance tests to measure the HCl mass flows at the control device inlet and outlet or the concentration of HCl exiting the control device according to the procedures described in Condition V.B.2.a above. Performance tests shall be conducted either annually or according to an alternative schedule that is approved by the Department, but no less frequently than every 2 1/2 years or twice per title V permit term. If any performance test shows that the HCl emission limitation is being exceeded, then the permittee is in violation of the emission limit. [§63.1162(a) and §2108.02.b]

e. The following test methods in Appendix A of 40 CFR Part 60 shall be used to determine compliance with Condition V.C.1.b above: [§63.1161(d)]

1) Method 1, to determine the number and location of sampling points, with the exception that no traverse point shall be within one inch of the stack or duct wall;
2) Method 2, to determine gas velocity and volumetric flow rate;
3) Method 3, to determine the molecular weight of the stack gas;
4) Method 4, to determine the moisture content of the stack gas; and
5) Method 26A, "Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources -- Isokinetic Method," to determine the HCl mass flows at the inlet and outlet of a control device or the concentration of HCl discharged to the atmosphere, and also to determine the concentration of Cl2 discharged to the atmosphere from acid regeneration plants. If compliance with a collection efficiency standard is being demonstrated, inlet and outlet measurements shall be performed simultaneously. The minimum sampling time for each run shall be 60 minutes and the minimum sample volume 0.85 dry standard cubic meters (30 dry standard cubic feet). The concentrations of HCl and Cl2 shall be calculated for each run as follows:

\[ C_{\text{HCl}}(\text{ppmv}) = 0.659 \times C_{\text{HCl}}(\text{mg/dscm}), \]

where \( C(\text{ppmv}) \) is concentration in ppmv and \( C(\text{mg/dscm}) \) is concentration in milligrams per dry standard cubic meter as calculated by the procedure given in Method 26A.

f. The permittee may use equivalent alternative measurement methods to those specified in paragraph V.C.2.c above, subject to approval by the Administrator and the Department [§63.1161(d)(2) and §63.1166(a)(2)]

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

3. Monitoring Requirements:

   a. The wet scrubber shall be provided with instrumentation that shall monitor the pressure drop across the scrubber at least once per shift. [§63.1160(b)(2) and §2103.12j]

   b. The permittee shall install, operate, and maintain systems for the measurement and recording of the scrubber makeup water flow rate and, if required, recirculation water flow rate. These flow rates must be monitored continuously and recorded at least once per shift while the scrubber is operating. Operation of the wet scrubber with excursions of scrubber makeup water flow rate and recirculation water flow rate less than the minimum values established during the performance test or tests will require initiation of corrective action as specified by the maintenance requirements in V.C.6.a below. [§63.1162(a)(2)]

   c. Failure to record each of the operating parameters listed in paragraph V.C.3.b above is a violation of the monitoring requirements. [§63.1162(a)(4)]

   d. Each monitoring device specified in paragraphs V.C.3.a and V.C.3.b above shall be certified by the manufacturer to be accurate to within 5 percent and shall be calibrated in accordance with the manufacturer's instructions but not less frequently than once per year. [§63.1162(a)(5)]

   e. The permittee may develop and implement alternative monitoring requirements subject to approval by the Administrator and the Department. [§63.1162(a)(6)]

4. Record Keeping Requirements:

   a. The permittee shall maintain a record of each inspection, including each item identified in paragraph V.C.6.a.4) below, that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other
corrective action taken, and the date of the repair, replacement, or other corrective action taken. [§63.1160(b)(2)(vii)]

b. As required by §63.10(b)(2), the permittee shall maintain records for 5 years from the date of each record of: [§63.1165(a)]

1) The occurrence and duration of each startup, shutdown, or malfunction of operation (i.e., process equipment);
2) The occurrence and duration of each malfunction of the air pollution control equipment;
3) All maintenance performed on the air pollution control equipment;
4) Actions taken during periods of startup, shutdown, and malfunction and the dates of such actions (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) when these actions are different from the procedures specified in the startup, shutdown, and malfunction plan;
5) All information necessary to demonstrate conformance with the startup, shutdown, and malfunction plan when all actions taken during periods of startup, shutdown, and malfunction (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. This information can be recorded in a checklist or similar form [see 40 CFR 63.10(b)(2)(v)];
6) All required measurements needed to demonstrate compliance with the standard and to support data that the permittee is required to report, including, but not limited to, performance test measurements (including initial and any subsequent performance tests) and measurements as may be necessary to determine the conditions of the initial test or subsequent tests;
7) All results of initial or subsequent performance tests;
8) All documentation supporting initial notifications and notifications of compliance status required by 40 CFR 63.9; and
9) Records of any applicability determination, including supporting analyses.

c. In addition to the general records required by paragraph V.C.4.b above, the permittee shall maintain records for 5 years from the date of each record of: [§63.1165(b)(1)]

1) Scrubber makeup water flow rate and recirculation water flow rate if a wet scrubber is used;
2) Calibration and manufacturer certification that monitoring devices are accurate to within 5 percent; and
3) Each maintenance inspection and repair, replacement, or other corrective action.

d. The permittee shall record the production and hours of operation of the 84” continuous coil HCl pickle line on a monthly basis. [§2103.12.j]

e. The permittee shall maintain records that document that compliance was demonstrated in accordance 40 CFR Part 63, Subpart CCC §63.1160(a)(1) [§2103.12.j]

f. The permittee shall keep the written operation and maintenance plan on record after it is developed to be made available for inspection, upon request, by the Department for the life of the affected source or until the source is no longer subject to these provisions. In addition, if the operation and maintenance plan is revised, the permittee shall keep previous (i.e., superseded) versions of the plan on record to be made available for inspection by the Department for a period of 5 years after each revision to the plan. [§63.1165(b)(3)]

g. Records for the most recent 2 years of operation must be maintained on site. Records for the previous 3 years may be maintained off site. [§63.1165(c)]
5. Reporting Requirements:

a. The permittee shall submit a notification of compliance status as required by 40 CFR 63.9(h). [§63.1163(e)]

b. The permittee shall report the results of any performance test required in condition V.C.2.a. [§63.1164(a)]

c. As required by 40 CFR§63.10(d)(5)(i), if actions taken by the permittee during a startup, shutdown, or malfunction of the 84” continuous coil pickle line (including actions taken to correct a malfunction) are consistent with the procedures specified in the startup, shutdown, and malfunction plan, the permittee shall state such information in a semiannual report. The report, to be certified by the permittee or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half. [§63.1164(c)(2)]

d. Any time an action taken by the permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures in the startup, shutdown, and malfunction plan, the permittee shall comply with all requirements of 40 CFR 63.10(d)(5)(ii). [§63.1164(c)(3)]

e. Reporting instances of non-compliance in accordance with condition V.C.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. (§2103.12.k.1)

6. Work Practice Standard:

a. In addition to the requirements specified in condition V.C.1.d above, the permittee shall prepare an operation and maintenance plan for the 84” continuous coil pickle line scrubber emission control device. The plan shall be submitted to the Department for approval. The plan must be consistent with good maintenance practices and, must at a minimum: [63.1160(b)(2) and §2102.04.b.6]

1) Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;
2) Require the manufacturer's recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system;
3) Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;
4) Require an inspection of each scrubber at intervals of no less than 3 months with:
   i. Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;
   ii. Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;
   iii. Repair or replacement of droplet eliminator elements as needed;
   iv. Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and
   v. Adjustment of damper settings for consistency with the required air flow;
5) If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Department may be used.
6) The permittee shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures
to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirements of this permit.

b. The permittee shall operate and maintain the 84” continuous coil HCl pickle line and the wet scrubber emission control device, in a manner consistent with good air pollution control practices for minimizing emissions at least to the level required by condition V.C.1.b above at all times, including during any period of startup, shutdown, or malfunction. Malfunctions must be corrected as soon as practicable after their occurrence in accordance with the startup, shutdown, and malfunction plan specified in paragraph V.C.6.c below. [§63.1164(c)]

c. As required by §63.6(e)(3) of 40 CFR 63, Subpart A, the permittee shall develop and implement a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the 84” continuous coil HCl pickle line and the wet scrubber emission control device during periods of startup, shutdown, or malfunction, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with the emission limitations in paragraph V.C.1.b above. [§63.1164(c)(1)]

7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
D. Process P008: No. 3 Five Stand Cold Reduction Mill

**Process Description:** Process P008 consists of steel roll uncoilers, cold reduction mill stands, steel roll hydraulic shear, and a roll coiler.

**Facility ID:** P008

**Max. Design Rate:** 3,767,676 tons of steel coils per year

**Capacity:** 2,500,000 tons of steel coils per year

**Raw Materials:** Steel Coils

**Control Device:** Cyclonic Mist Eliminator

As identified above, Process P008 consists of following types of equipment: steel roll uncoilers, cold reduction mill stands, steel coil hydraulic shear, and a roll coiler.

1. **Restrictions - Installation Permits, Standards for Issuance, BACT**

   a. The permittee shall not, operate or allow to be operated, the cold reduction mill unless the five mill stands are equipped with a capture system that exhausts to a mist eliminator control system. The collection and control system shall be properly maintained and operated, controlling oil mist emissions from the cold reduction mill, according to the following specifications while the line is in operation: [Installation Permit No. 0050-I002a, §2102.04.b.6, and 25 PA Code §129.99]

      1) The capture system shall have a negative air flow into the system at all times and partially enclose the mill stands with openings for the steel sheet inlet and outlet and openings for observation and access to the rollers and steel.

      2) The mist eliminator control system shall be comprised of five identical cyclone mist eliminators, in parallel with a design minimum combined air flowrate of 200,000 ACFM.

      3) The North and South fans shall maintain an inlet static pressure that is no more negative than -8.0" w.c.

   b. The permittee shall conduct cleaning of the cyclone mist eliminators specified in Condition V.D.1.a above once every four months. This cleaning will be conducted in such a way as to thoroughly remove all material or corrosion that could decrease the mist eliminator efficiencies. Notwithstanding the previous, cleaning shall be conducted immediately following any inspection of the mist eliminators as specified in Condition V.D.3.a below if warranted by the inspection findings or when a measured inlet pressure exceeds Condition V.D.1.a.3) above. [Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

   c. The permittee shall not operate or allow to be operated, the cold reduction mill in such a manner that the production during any 12 consecutive months exceeds 2,500,000 tons of steel or the daily average hourly production rate exceeds 525 tons of steel per hour based on the number of hours of operation in a day. [Installation Permit No. 0050-I002a]

   d. The permittee shall operate the Cold Reduction Mill with a water-oil emulsion in which the oil content, by volume is less than or equal to 7%. The lubricating oil used in the water-oil emulsion shall have a VOC content, by weight less than or equal to 2%. [Installation Permit No. 0050-I002a; RACT Order No. 258, §2105.06; 25 PA Code §129.99]
c. Emissions from the cold reduction mill shall not exceed the limitations in Table V-D-1 at any time: [Installation Permit No. 0050-I002a, 2/12/04 and §2102.04.b.6]

Table V-D-1 - No. 3 Five Stand Cold Reduction Mill Emission Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/ton steel rolled</th>
<th>lbs/hour</th>
<th>tons/year ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
<tr>
<td>Volatile Organic Compound</td>
<td>0.025</td>
<td>13.12</td>
<td>31.25</td>
</tr>
</tbody>
</table>

¹A year is defined as any consecutive 12-month period

2. Testing Requirements:
   a. The permittee shall conduct emission testing for particulate matter on the cold reduction mill oil mist capture and control system in order to determine compliance with the emissions limitations of condition V.D.1.e above. Testing shall be at least once every 5 years thereafter. Such testing shall be performed according to EPA approved test methods No. 1, No. 2, No. 3, No. 4 and No. 5 as specified in 40 CFR 60, Appendix A and in accordance with Section §2108.02 of Article XXI, or as approved by the Department. [Installation Permit No. 0050-I002a, 2/12/04 and §2108.02.a.]
   b. The Department reserves the right to require emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. The permittee shall inspect the cold reduction mill capture system and control system specified in Condition V.D.1.a above to insure the proper operation and physical integrity of all collection and control equipment and verify negative air flow into the collection and control system daily to insure compliance with Condition V.D.1.a above. The permittee shall inspect one cyclone per week so that each cyclone is inspected a minimum of once every five weeks to insure that the cyclones are clean and free of all material or corrosion that could decrease the efficiencies of the cyclones. Notwithstanding the previous, inspections of all other cyclones shall be conducted immediately following the specified monthly single cyclone inspection if the cyclone is found to be nonfunctional, in a condition that would reduce the operating efficiency or if a measured inlet pressure exceeds Condition V.D.1.a.3) above. Any excursions from Condition V.D.1.a above shall be corrected as soon as possible. [Installation Permit No. 0050-I002a, 2/12/04; 40 C.F.R. §64.3 & 64.6; and 25 PA Code §129.100]
   b. Instrumentation shall be provided that can directly measure the inlet pressure of each of the collection and control system exhaust fans to within 1/10” w.c. The inlet pressure shall be measured for each fan weekly and after any cleaning conducted on the cyclones. [Installation Permit No. 0050-I002a, 2/12/04; 40 C.F.R. §64.3 & §64.6; and 25 PA Code §129.100]
4. **Record Keeping Requirements:**
   
a. The permittee shall record the production and the hours of operation of the cold reduction mill on a daily basis. [Installation Permit No. 0050-I002a, 2/12/04 and §2103.12.j]

b. The permittee shall record the type and VOC content of all rolling oils, the percent of rolling oil in the water-oil emulsion as applied and the amount of emulsion used for the cold reduction mill on a daily basis. In addition, all emission test data from tests required by Condition V.D.2.a above shall be retained at the facility as per Condition V.D.4.d below. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.9(b); §2103.12.j; 25 PA Code §129.100]

c. The results of the inspections required by Condition V.D.3.a above shall be recorded weekly. The monitoring data specified Condition V.D.3.b above shall be recorded weekly and after every cyclone cleaning. Episodes of non-compliance with Conditions V.D.1.a, V.D.1.b or V.D.3.a above and corrective actions taken shall be recorded upon occurrence. All such records shall be summarized monthly. [Installation Permit No. 0050-I002a, 2/12/04 and 40 C.F.R. §64.9(b); §2103.12.j]

d. 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. [Installation Permit No. 0050-I002a, 2/12/04; §§2103.12.j.2; 25 PA Code §129.100]

5. **Reporting Requirements:**
   
a. The permittee shall provide quarterly reports that contain monthly summaries of production, hours of operation, and maximum percent VOC content, by weight, of the rolling oil and the maximum percent, by weight, of the rolling oil in the water-oil emulsion. The due dates of these reports are prescribed in General Condition III.15.e above. [Installation Permit No. 0050-I002a, 2/12/04; §2103.12.k.1; 40 C.F.R. §64.9(a)]

b. The permittee shall report the exhaust fans inlet pressures weekly measurements specified in Condition V.D.3.b above within thirty days of the end of each calendar half as required in General Condition III.15.d. §2103.12.k.1; 40 C.F.R. §64.9(a)]

c. The permittee shall report all instances of non-compliance with Conditions V.D.1.a, V.D.1.b, V.D.1.c, V.D.1.d, V.D.1.e, V.D.3.a, and V.D.3.b above along with all corrective action taken to restore the subject equipment to compliance, to the Department every three months in accordance with General Condition III.15.e above. [§2103.12.k.1]

d. Reporting instances of non-compliance in accordance with Condition V.D.5.c above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k.1]

6. **Work Practice Standard:**
   
a. The permittee shall maintain and operate the cold rolling mill in accordance with good air pollution control practices, by performing regular maintenance as required by condition V.D.3, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258; 25 PA Code §129.99]
7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
E. Process P009: HPH Annealing Furnaces

**Process Description:** The HPH Annealing Process consists of 31 individual movable furnaces with 58 bases in one unit that treat coiled steel rolls. Each furnace is fired with coke oven gas enriched with natural gas and has a maximum heat input rating of 4.9 MMBtu/hr

**Facility ID:** P009

**Max. Design Rate:** 38,000 tons of sheets per year per furnace (31 individual furnaces)

**Capacity:** 38,000 tons of sheets per year per furnace

**Raw Materials:** Steel Coils, Annealing Gases, Coke Oven Gas, Natural gas

**Control Device:** N/A.

As identified above, Process P009 consists of 31 individual, moveable batch annealing furnaces with 58 stationary bases.

1. **Restrictions:**
   a. The HPH Annealing Furnaces shall only combust coke oven gas and natural gas. [§2102.04.b.5]
   b. The permittee shall not operate or allow to be operated, the HPH annealing furnaces in a manner such that emissions of PM-10 from the HPH annealing furnaces exceed at any time, 0.011 lbs/ton of steel. [§2104.02.d.1]
   c. The permittee shall not operate, or allow to be operated, HPH furnaces No. 1 through No. 31 in such manner that emissions of sulfur oxides from each furnace, expressed as sulfur dioxide, exceed 1.0 lb/MMBtu at any time: [§2104.03.a.2.A]
   d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in HPH furnaces No. 1 through No. 31, 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. [§2105.21.h.4]
   e. Emissions from HPH furnaces No. 1 through No. 31, shall not exceed the limitations in Table V-E-1 below at any time: [§2104.02.d.1, §2104.03.a.2.A and §2105.21.h.4]

**Table V-E-1 - HPH Annealing Furnace Emissions**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr 1 (each unit)</th>
<th>tons/yr 1 (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.04</td>
<td>0.10</td>
<td>0.43</td>
<td>13.33</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.04</td>
<td>0.10</td>
<td>0.43</td>
<td>13.33</td>
</tr>
<tr>
<td>NOx</td>
<td>0.49</td>
<td>0.74</td>
<td>3.22</td>
<td>99.82</td>
</tr>
<tr>
<td>CO</td>
<td>0.47</td>
<td>0.21</td>
<td>2.07</td>
<td>64.17</td>
</tr>
<tr>
<td>VOC</td>
<td>0.03</td>
<td>0.01</td>
<td>0.14</td>
<td>4.21</td>
</tr>
</tbody>
</table>

1 A year is defined as any consecutive 12-month period
f. SO$_2$ emissions from the HPH Annealing Furnaces (aggregate) shall not exceed the limitations in Table V-A-2 below: [§§2105.21.h; SO$_2$ SIP IP 0050-1008, Condition V.A.1.b]

<table>
<thead>
<tr>
<th>TABLE V-E-2</th>
<th>SO$_2$ Emission Limitations for each Hot Strip Mill Reheat Furnace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30 day rolling average limit (lb/hr)*</td>
</tr>
<tr>
<td>12.0</td>
<td>13.58</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO$_2$ State Implementation Plan (SIP) Permit Revision and USEPA SO$_2$ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO$_2$ State Implementation Plan (SIP) Permit Revision and USEPA SO$_2$ Guidance dated September 14, 2017.

2. Testing Requirements:
   a. Emissions of SO$_2$ shall be determined by converting the H$_2$S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.E.1.f above. [SO$_2$ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]
   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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H$_2$S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3; §§2103.12.i]
   b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.E.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.E.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (§2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall maintain hourly, monthly, 12 month rolling totals of the fuel type, fuel usage (COG and natural gas), hours of operation and sulfur compound concentration expressed as H$_2$S in grains per 100 dscf in coke oven gas used for combustion, for the HPH Annealing Furnaces. [SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]
   b. The permittee shall calculate emissions to demonstrate compliance with conditions V.E.1.b, V.E.1.c and Table V-E-1. These calculations shall be recorded on a monthly basis.” [§2103.12.h.5.B]
   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; 25 PA Code §129.100]

5. **Reporting Requirements:**

a. The permittee shall submit semiannual reports, as prescribed in General Condition III.15.d, of monthly fuel usage for each fuel combusted in the HPH Annealing Furnaces and the hours of operation of each furnace. [§2103.12.k]

b. The permittee shall report the concentration of H₂S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

c. Reporting instances of non-compliance in accordance with V.E.5.b above does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. **Work Practice Requirements:**

a. The permittee shall maintain and operate the HPH Annealing Furnaces in accordance with good combustion and air pollution control practices by performing regular maintenance and operating the furnaces in accordance with the manufacturer’s specifications, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258, 25 PA Code §129.97(c)(3)]

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
F. Process P010: Open Coil Annealing Furnaces No. 1 Through No. 16

**Process Description:** The Open Coil Annealing Process consists of 16 individual furnaces that heat treat open coiled steel rolls. Each furnace is fired with coke oven gas that is enriched with natural gas. Furnaces No. 1 through No. 9 have a maximum heat input rating of 7.2 MMBTU/Hr each; furnaces No. 10 through No. 13 have a maximum heat input rating of 9.0 MMBTUs/Hr, each; furnace No. 14 has a maximum heat input rating of 5.4 MMBtu/hr and Furnaces No. 15 and 16 have a maximum heat input rating of 7.47 MMBtu/hr, each.

**Facility ID:** P010

**Max. Design Rate:** 176,000 tons of sheets per year

**Capacity:** 176,000 tons of sheets per year

**Raw Materials:** Steel Coils, Annealing Gases, Coke Oven Gas, Natural Gas

**Control Device:** N/A

1. **Restrictions:**

   a. Only coke oven gas and natural gas shall be combusted in the No. 1 through No. 16 Open Coil Annealing Furnaces. [§2102.04.b.5; §2102.04.b.6 and IP No. 0050-I006, Condition V.A.1.a]

   b. The permittee shall not operate or, or allow to be operated Open Coil Annealing Furnace No. 14 unless the furnace is properly operated and maintained according to the following specifications, at all times: [Installation Permit No. 0050-I003, and §2102.04.b.6]

      1) All furnace burners shall be low-NOX burners with maximum NOx emissions of 0.18 Lbs/MMBtu and 0.29 Lbs/MMBtu for natural gas and coke oven gas combustion, respectively.

      2) All burners shall combust natural gas and/or coke oven gas only.

      3) Natural gas fuel usage, adjusted to a heating value of 1,020 BTU/SCF shall not exceed 46.5 MMSCF per consecutive twelve-month period. Coke oven gas usage, adjusted to 514.4 BTU/SCF shall not exceed 92 MMSCF per consecutive twelve-month period.

   c. The permittee shall not operate, or allow to be operated Open Coil Annealing Furnace No. 14 unless the low-NOX burners specified in Condition V.F.1.b above are properly installed, maintained, and operated consistent with good air pollution control practice. [§2102.04.b.6]

   d. The permittee shall not operate or allow to be operated Open Coil Annealing Furnaces No. 1 through No. 13 fueled entirely by natural gas in such a manner that the emissions of particulate matter exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   e. The permittee shall not operate or allow to be operated Open Coil Annealing Furnaces No. 1 through No. 13 fueled entirely by coke oven gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   f. The permittee shall not operate or allow to be operated Open Coil Annealing Furnaces No. 1 through No. 13 fueled with natural gas and coke oven gas, in such a manner that the emissions of particulate matter exceeds the rate determined by the formula: [§2104.02.a.3]

\[
A = \sum x_i a_i
\]

Where: 
- \( A \) = Allowable emissions in pounds per million BTUs of actual heat input,
- \( i \) = Fuel type (i.e. natural gas and coke oven gas),
x_i = Fraction of total actual heat input in BTUs provided by fuel type i, and
a_i = Allowable emissions in pounds per million BTUs of actual heat input for fuel type i, where a_i = 0.008 for natural gas and 0.02 for coke oven gas.

g. The permittee shall not operate, or allow to be operated, Open Coil Annealing Furnaces No. 1 through No. 13 in such manner that emissions of sulfur oxides, expressed as sulfur dioxide, exceed 1.0 lb/MMBtu at any time: [§2104.03.a.2.A]

h. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Open Coil Annealing Furnaces No. 1 through No. 16, 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. [§2105.21.h.4; IP-0050-I006, Condition V.A.1.b]

i. Emissions from Open Coil Annealing Furnaces No. 1 through No. 9, shall not exceed the limitations for each furnace in Table V-F-1 below at any time: [§2104.02.a.1, §2104.03.a.2.A and §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr ¹ (each unit)</th>
<th>tons/yr ¹ (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.06</td>
<td>0.14</td>
<td>0.63</td>
<td>5.68</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.06</td>
<td>0.14</td>
<td>0.63</td>
<td>5.68</td>
</tr>
<tr>
<td>NOx</td>
<td>0.72</td>
<td>2.88</td>
<td>12.61</td>
<td>113.46</td>
</tr>
<tr>
<td>CO</td>
<td>0.70</td>
<td>0.30</td>
<td>3.05</td>
<td>27.42</td>
</tr>
<tr>
<td>VOC</td>
<td>0.05</td>
<td>0.02</td>
<td>0.20</td>
<td>1.80</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

j. Emissions from Open Coil Annealing Furnaces No. 10 through No. 13, shall not exceed the limitations for each furnace in Table V-F-2 below at any time: [§2104.02.a.1, §2104.03.a.2.A and §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each unit (natural gas)</th>
<th>lbs/hr – each unit (coke oven gas)</th>
<th>tons/yr ¹ (each unit)</th>
<th>tons/yr ¹ (combined)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.07</td>
<td>0.18</td>
<td>0.79</td>
<td>3.15</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.07</td>
<td>0.18</td>
<td>0.79</td>
<td>3.15</td>
</tr>
<tr>
<td>NOx</td>
<td>0.90</td>
<td>3.60</td>
<td>15.77</td>
<td>63.08</td>
</tr>
<tr>
<td>CO</td>
<td>0.87</td>
<td>0.38</td>
<td>3.81</td>
<td>15.24</td>
</tr>
<tr>
<td>VOC</td>
<td>0.06</td>
<td>0.02</td>
<td>0.25</td>
<td>1.00</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

k. Emissions from Open Coil Annealing Furnace No. 14, shall not exceed the limitations in Table V-
Table V-F-3 - Open Coil Annealing Furnace No. 14 Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.04</td>
<td>0.07</td>
<td>0.30</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.04</td>
<td>0.05</td>
<td>0.22</td>
</tr>
<tr>
<td>NOx</td>
<td>0.75</td>
<td>1.20</td>
<td>5.20</td>
</tr>
<tr>
<td>CO</td>
<td>0.47</td>
<td>0.21</td>
<td>2.10</td>
</tr>
<tr>
<td>VOC</td>
<td>0.03</td>
<td>0.02</td>
<td>0.13</td>
</tr>
</tbody>
</table>

² A year is defined as any consecutive 12-month period

Table V-F-4 - Open Coil Annealing Furnaces No. 15 and No. 16 Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr – each furnace (natural gas)</th>
<th>lbs/hr – each furnace (coke oven gas)</th>
<th>tons/yr³- (each furnace)</th>
<th>tons/yr³- (both furnaces)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.015</td>
<td>0.102</td>
<td>0.45</td>
<td>0.90</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.015</td>
<td>0.071</td>
<td>0.31</td>
<td>0.63</td>
</tr>
<tr>
<td>NOx</td>
<td>0.28</td>
<td>0.35</td>
<td>1.52</td>
<td>3.04</td>
</tr>
<tr>
<td>CO</td>
<td>0.68</td>
<td>0.30</td>
<td>2.96</td>
<td>5.93</td>
</tr>
<tr>
<td>VOC</td>
<td>0.044</td>
<td>0.020</td>
<td>0.19</td>
<td>0.39</td>
</tr>
</tbody>
</table>

³ A year is defined as any consecutive 12-month period

SO₂ emissions from the Open Coil Annealing Furnaces No. 1 through No. 16 (aggregate) shall not exceed the limitations in Table V-F-5 below: [§2105.21.h; SO₂ SIP IP 0050-1008, Condition
TABLE V-F-5
SO₂ Emission Limitations for Open Coil Annealing Furnaces No. 1 through No. 16 (aggregate)

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>11.50</td>
<td>13.02</td>
<td>50.37</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

** Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:
   a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate to pounds per hour to determine compliance with the emission limitations in condition V.F.1.o, Table V-A-5 above. [SO₂ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]
   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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirement:
   a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SIP IP 0050-1008, Condition V.A.3.a; IP No. 0050-1006, Condition V.A.3; §§2103.12.i]
   b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.F.3.a V.E.3.aabove shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.F.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-1006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:
   a. The permittee shall record, hourly monthly, the type and total amount of fuel used (COG and natural gas) and the total production of furnaces No. 1 through No. 16, combined. [§2103.12.j and IP No. 0050-1003, 6/29/00 and IP No. 0050-1006, Condition V.A.4.a; SO₂ SIP IP 0050-1008, Condition V.A.4.a]
   b. The permittee shall maintain monthly and 12 month rolling totals of the combined hours of operation of OCA Furnaces No. 1 through No. 16, and hourly summaries of the sulfur compound concentration expressed as H₂S in grains per 100 dscf in coke oven gas used for combustion in
furnaces No. 1 through No. 16. [§2103.12.h.5.B, §2103.12.j and IP No. 0050-1006, Condition V.A.4.b; SO₂ SIP IP 0050-1008, Condition V.A.4.a]

c. 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. [§2102.04.b.5 and §2102.04.b.6 and IP No. 0050-1006, Condition V.A.4.c]

d. 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. [§2102.04.b.6 and IP No. 0050-1006, Condition V.A.4.d, 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report the concentration of H₂S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General Condition III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO₂ SIP IP 0050-1008, Condition V.A.5.a; IP No. 0050-1006, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with condition V.F.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k and IP No. 0050-1006, Condition V.A.5.b]

6. Work Practice Requirements:

The permittee shall maintain and operate Open Coil Annealing Furnaces No. 1 through No. 16 in accordance with good combustion and air pollution control practices by performing regular maintenance and operating the furnaces in accordance with the manufacturer’s specifications, at all times, and measure the sulfur concentration of the coke oven gas with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258, 25 PA Code §129.97(c)(3), and §2102.04.b.6]

7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
G. Process P011: Continuous Annealing

Process Description: The Continuous Annealing Process consists of one furnace rated at 45 MMBtu/hr along with associated coiling, uncoiling and cleaning equipment.

Facility ID: P011

Max. Design Rate: 348,000 tons of sheets per year

Capacity: 348,000 tons of sheets per year

Raw Materials: Steel Coils, Caustic Solutions, Annealing Gases, Coke Oven Gas, Natural Gas

Control Device: N/A

1. Restrictions:

a. Only coke oven gas and natural gas shall be combusted in the Continuous Annealing furnace. [§2102.04.b.5]

b. The permittee shall not operate or allow to be operated Continuous Annealing furnace fueled entirely by natural gas in such a manner that the emissions of particulate matter exceed 0.008 lbs/MMBTU of actual heat input, at any time. [§2104.02.a.1]

c. The permittee shall not operate or allow to be operated Continuous Annealing furnace fueled entirely by coke oven gas in such a manner that the emissions of particulate matter exceed 0.02 lbs/MMBTU of actual heat input, at any time. [§2104.02.a.1]

d. The permittee shall not operate or allow to be operated Continuous Annealing furnace fueled with natural gas and coke oven gas, in such a manner that the emissions of particulate matter exceed the rate determined by the formula: [§2104.02.a.3]

\[ A = \sum x_i a_i \]

where \( A \) = allowable emissions in pounds per million BTUs of actual heat input,

\( i \) = fuel type (i.e. natural gas and coke oven gas),

\( x_i \) = fraction of total actual heat input in BTUs provided by fuel type \( i \), and

\( a_i \) = allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

e. The permittee shall not operate, or allow to be operated, Continuous Annealing furnace in such manner that emissions of sulfur oxides, expressed as sulfur dioxide, exceed 1.0 lb/mmBtu at any time. [§2104.03.a.2.A]

f. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Continuous Annealing furnace, 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. [§2105.21.h.4]
g. Emissions from Continuous Annealing Line furnace, shall not exceed the limitations specified in Table V-G-1 below, at any time: [§2104.02.a.1, §2104.03.2.A, §2105.21.h.4]

Table V-G-1
Continuous Annealing Furnace Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.36</td>
<td>0.90</td>
<td>3.94</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.36</td>
<td>0.90</td>
<td>3.94</td>
</tr>
<tr>
<td>NOx</td>
<td>4.50</td>
<td>18.00</td>
<td>78.84</td>
</tr>
<tr>
<td>CO</td>
<td>4.35</td>
<td>1.66</td>
<td>19.04</td>
</tr>
<tr>
<td>VOC</td>
<td>0.28</td>
<td>0.12</td>
<td>1.25</td>
</tr>
</tbody>
</table>

¹A year is defined as any consecutive 12-month period

h. SO₂ emissions from the Continuous Annealing Furnace shall not exceed the limitations in Table V-G-2 below: [§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b; §2104.03.2.A, §2105.21.h.4]

Table V-G-2
SO₂ Emission Limitations for the Continuous Annealing Furnace

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.07</td>
<td>9.14</td>
<td>35.35</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017. **Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September

2. Testing Requirements:
   a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.G.1.h above. [§2103.12.h]
   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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:
   a. The permittee shall measure monthly the quantity of natural gas and coke oven gas combusted in the Annealing Furnace. [§2103.12.i]
   b. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]
c. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.G.3.b above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.G.3.b. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-1006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order Number 258]

1) The date of the annual tune-up;
2) The name of the service company and/or individuals performing the annual tune-up;
3) The operating rate or load after the annual tune-up; and
4) The CO and NOX emission rate after the annual tune-up.

b. The permittee shall maintain hourly records of fuel type, fuel usage (COG and natural gas), hours of operation, and hourly H2S concentration in grains per 100 dscf. [SO2 SIP IP 0050-1008, Condition V.A.4.a; §§2103.12.h.5.B; §§2103.12.j; §2103.12.h.5.B]

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; 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.G.5.a does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Requirements:

a. The permittee shall perform an annual adjustment or "tune-up" on the combustion process of the equipment once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No. 258, 25 PA Code §129.97(b)(1)]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper
calibration and operation as specified by the manufacturer.

PERMIT SHIELD IN EFFECT
H. Process P012: No. 1 Continuous Galvanizing Line

Process Description: The Continuous Galvanizing Process consists of one natural gas-fired preheat furnace rated at 50 MMBTUs/hr and one natural gas-fired galvanneal furnace rated at 18 MMBTUs/hr, along with associated coiling, uncoiling and cleaning equipment.

Facility ID: P012
Max. Design Rate: 187,700 tons of sheets per year
Capacity: 187,700 tons of sheets per year
Raw Materials: Steel Coils, Zinc, Treatment Chemicals, and Natural Gas
Control Device: N/A

1. Restrictions
   a. Only natural gas shall be combusted in the No. 1 Continuous Galvanizing Line preheat and galvanneal furnaces [§2102.04.b.5]
   b. The permittee shall not operate, or allow to be operated the No. 1 Galvanizing Line Preheat Furnace and galvanneal furnace in such a manner that the emissions of particulate matter from each furnace exceeds 0.008 lbs/mmBtu when combusting natural gas. [§2104.02.a.1]
   c. Emissions from the continuous galvanizing line furnaces shall not exceed the limitations specified in Table V-H-1 below, at any time: [25 PA Code §129.97(g)(1)(i); §2104.02.a.1.A; and §2104.03.a.1]

Table V-H-1 - -No. 1 Continuous Galvanizing Line Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Preheat Furnace</th>
<th>Galvanneal Furnace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lbs/hr (natural gas)</td>
<td>ton/yr 1</td>
</tr>
<tr>
<td>Particulate Matter</td>
<td>0.40</td>
<td>1.75</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.40</td>
<td>1.75</td>
</tr>
<tr>
<td>CO</td>
<td>4.83</td>
<td>21.16</td>
</tr>
<tr>
<td>SO2</td>
<td>0.03</td>
<td>0.13</td>
</tr>
<tr>
<td>NOX</td>
<td>3.0</td>
<td>13.14</td>
</tr>
<tr>
<td>VOC</td>
<td>0.32</td>
<td>1.40</td>
</tr>
</tbody>
</table>

1A year is defined as any consecutive 12-month period
2The hourly rate of 3.0 lbs/hr is less than the presumptive RACT rate of 0.10 lb NOX/MMBtu

2. Testing Requirements:

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

3. Monitoring Requirements:
The permittee shall monitor the monthly quantity of natural gas combusted in the No. 1 Galvanizing Line furnaces. [§2103.12.i]

4. **Record Keeping Requirements:**
   a. The permittee shall maintain monthly, 12 month rolling totals of the following data for the No. 1 Galvanizing Line Preheat and Galvanneal Furnaces [§2103.12.5.B]
      1) Fuel usage;
      2) Monthly production (tons of sheet processed);
      3) Hours of operation.
   b. 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; 25 PA Code §129.100]

5. **Reporting Requirements:**
   a. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. If all the terms and conditions of this permit are complied with during the reporting period, then no report is necessary under this permit condition. [§2103.12.k]
   b. Reporting instances of non-compliance in accordance with V.H.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. **Work Practice Standards:**
   a. The permittee shall maintain and operate the No. 1 Continuous Galvanizing Line in accordance with good combustion and air pollution control practices by performing regular maintenance, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258 and 25 PA Code §129.97(c)(3)]

7. **Additional Requirements:**

   None except as provided elsewhere.

   **PERMIT SHIELD IN EFFECT**
I. Process P013: No. 2 Continuous Galvanizing & Aluminum Coating Lines

Process Description: The Continuous Galvanizing & Aluminum Coating Process consists of one preheat furnace rated at 18 MMBTU/HR along with associated cleaning, treating and galvalume equipment

Facility ID: P013
Max. Design Rate: 156,400 tons of sheets per year
Capacity: 156,400 tons of sheets per year
Raw Materials: Steel Coils, Natural Gas, Zinc, Galvalume, Treatment Chemicals, Caustic Solution, Annealing Gases, Coating Oil

Control Device: NA

1. Restrictions:

   a. Only natural gas shall be combusted in the No. 2 Continuous Galvanizing and Aluminum Coating Line preheat furnace. [§2102.04.b.5]

   b. The permittee shall not operate, or allow to be operated the No. 2 Galvanizing & Aluminum Coating Line Preheat Furnace in such a manner that the emissions of particulate matter exceed 0.008 lbs/MMBTU when combusting natural gas. [§2104.02.a.1]

   c. The permittee of each coil coating line shall limit organic HAP emissions to no more than 0.046 kilograms (kg) of organic HAP per liter of solids applied during each 12-month compliance period. [§63.5120(a)(2)]

   d. Emissions from the preheat furnace shall not exceed the limitations specified in Table V-I-1 below, at any time: [§2104.02.a.1.A and §2104.03.a.1]

Table V-I-1 - No. 2 Continuous Galvanizing & Aluminum Coating Lines Emission Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>Tons/Yr¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter</td>
<td>0.14</td>
<td>0.61</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.14</td>
<td>0.61</td>
</tr>
<tr>
<td>CO</td>
<td>1.74</td>
<td>7.62</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.01</td>
<td>0.04</td>
</tr>
<tr>
<td>NOₓ</td>
<td>7.20</td>
<td>31.54</td>
</tr>
<tr>
<td>VOC</td>
<td>0.11</td>
<td>0.48</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

2. Testing Requirements:

   a. On and after June 10, 2005, the permittee shall determine the organic HAP weight fraction of each coating material applied by following one of the procedures in paragraphs §63.5160(b)(1) through (4) and the solids content of each coating material applied by following the procedure in paragraph §63.5160(c). [§63.5160]
b. For the purpose of demonstrating continuous compliance with Condition V.I.1.c above, a compliance period consists of 12 months. Each month after the end of the initial compliance period is the end of a compliance period consisting of that month and the preceding 11 months. [§63.5130(e)]

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

3. **Monitoring Requirements:**

   a. The permittee shall demonstrate compliance with the emission limitation in Condition V.I.1.c above by using at least one of the compliance options in §63.5170(a) or (b). The permittee may apply any of the compliance options to an individual coil coating line, or to multiple lines as a group, or to the entire affected source. [§63.5170(a) and (b)]

4. **Record Keeping Requirements:**

   a. The permittee shall maintain monthly, 12 month rolling totals of the following data for the No. 2 Galvanizing & Aluminum Coating Line Preheat Furnace: [§2103.12.h.5.B]

      1) Fuel usage;
      2) Hours of operation;
      3) Production (tons of sheet processed).

   b. On and after June 10, 2005, the permittee subject to 40 CFR 63, Subpart SSSS shall maintain the following records: [§63.5190(a)]

      1) Records of the coating lines on which the permittee used each compliance option in Condition V.I.3.a above and the time periods (beginning and ending dates and times) the permittee used each option.

      2) Records specified in 40 CFR Part 63, §63.10(b)(2) of all measurements needed to demonstrate compliance including:

         i. Organic HAP content data for the purpose of demonstrating compliance in accordance with §63.5160(b);
         ii. Volatile matter and solids content data for the purpose of demonstrating compliance in accordance with §63.5160(c);
         iii. Material usage, HAP usage, volatile matter usage, and solids usage and compliance demonstrations using these data in accordance with §63.5170(a) and (b);

   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; 25 PA Code §129.100]

5. **Reporting Requirements:**

   a. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. If all the terms and conditions of this permit are complied with during the reporting period, then no report is necessary.
under this permit condition.  [§2103.12.k]

b. The permittee shall maintain records that document that initial notification was made in accordance with 40 CFR Part 63, Subpart SSS [§63.5180(b)]

c. The permittee shall submit semi-annual compliance reports containing the following information: [§63.5180(g)]

1) The semi-annual compliance report shall contain the following information:
   i. Company name and address.
   ii. Statement by a responsible official with that official's name, title, and signature, certifying the accuracy of the content of the report.
   iii. Date of report and beginning and ending dates of the reporting period. The reporting period is the 6-month period ending on June 30 or December 31. Note that the information reported for each of the 6 months in the reporting period will be based on the last 12 months of data prior to the date of each monthly calculation.
   iv. Identification of the compliance option or options specified in Table 1 to 40 CFR Part 63, §63.5170 that the permittee used on each coating operation during the reporting period. If you switched between compliance options during the reporting period, you must report the beginning dates you used each option.
   v. A statement that there were no deviations from the standards during the reporting period.

d. The permittee shall submit, for each deviation occurring at an affected source subject to Subpart SSSS, the semi-annual compliance report containing the information in Condition V.I.5.c.1) above and the following information:  [§63.5180(h)]

1) The total operating time of each affected source during the reporting period.
2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable, and the corrective action taken.
3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause other than downtime associated with zero and span and other daily calibration checks, if applicable).

e. Reporting instances of non-compliance in accordance with V.I.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate.  [§2103.12.k]

6. **Work Practice Standards:**

   The permittee shall maintain and operate the No. 2 Continuous Galvanizing and Aluminum Coating Line preheat furnace in accordance with good combustion and air pollution control practices by performing regular maintenance and operating the preheat furnaces in accordance with the manufacturer’s specifications, at all times with the exception of emergency or planned outages, repairs or maintenance. [RACT Order No. 258, 25 PA Code §129.97(c)(3)]

7. **Additional Requirements:**

   None except as provided elsewhere

---

**PERMIT SHIELD IN EFFECT**
J. Process P015: Coke Oven Gas Flares No. 1 through No. 3 and Peachtree A & B Flare

<table>
<thead>
<tr>
<th>Process Description:</th>
<th>Four flares used for combusting excess coke oven gas.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility ID:</td>
<td>P015</td>
</tr>
<tr>
<td>Max. Design Rate:</td>
<td>6.75 million cubic feet per day of COG, each</td>
</tr>
<tr>
<td>Capacity:</td>
<td>27 million cubic feet per day for four flares</td>
</tr>
<tr>
<td>Raw Materials:</td>
<td>Coke oven gas</td>
</tr>
<tr>
<td>Control Device:</td>
<td>Flare minimization plan</td>
</tr>
</tbody>
</table>

1. Restrictions:

   a. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in C.O.G. Flares No.1 to No. 3 and Peachtree Flare, 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. [§2105.21.h.4]

2. Testing Requirements:

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

3. Monitoring Requirements:

   a. The permittee shall measure the sulfur concentration of all coke oven gas used for combustion or flaring at the facility, a minimum of once per each successive twenty-four hour time period. The sulfur concentration shall be expressed and recorded as hydrogen sulfide. Measurements of hydrogen sulfide concentrations in coke oven gas shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy this condition (V.K.3.a). However, if there is a change to the current operating scenario, the sulfur concentration measurements required by this condition (V.K.3.a) will be taken at the Irvin Plant. [§2103.12.h.5.B]

4. Record Keeping Requirements

   a. The permittee shall maintain daily and 12 month rolling totals of the fuel usage, COG sulfur concentration (expressed as H₂S) and hours of operation for Flares No.1, No. 2 and No. 3 and the Peachtree Flare: [§2103.12.h.5.B, 25 PA Code §129.100]

   b. 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; 25 PA Code §129.100]

5. Reporting Requirements:

   a. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]

   b. Reporting instances of non-compliance in accordance with V.J.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]
c. The permittee shall submit the flare minimization electronically to the Allegheny County Health Department Air Quality program within 90 days after the issuance of this permit. [§2103.12.k]

6. Work Practice Standards:

The U.S. Steel Irvin Plant shall implement a flare minimization plan for all four flares that includes: [§2103.12.a.2.B; 25 PA Code §129.99]

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 shall 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) A primary baseline flow rate that shall 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.

d. 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.

e. The facility shall 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.

f. The plan shall 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
shall 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.

g. The flare minimization plan shall be implemented within 90 days after the issuance of this permit.

7. Additional requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
K. **Boiler No. 1**

**Process Description:** One 79.8 MMBTUs/hr natural gas and coke oven gas fired boiler  
**Facility ID:** B001  
**Max. Design Rate:** 79.8 MMBtu/hr  
**Capacity:** 79.8 MMBtu/hr  
**Raw Materials:** Coke oven gas and natural gas  
**Control Device:** N/A

This emission unit is also subject to the following requirements and restrictions:

1. **Restrictions:**
   
a. Only coke oven gas and natural gas shall be combusted in Boiler No. 1. [2102.04.b.5]
   
b. The permittee shall not operate, or allow to be operated Boiler No. 1 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter exceed 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   
c. The permittee shall not operate, or allow to be operated Boiler No. 1 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   
d. The permittee shall not operate or allow to be operated Boiler No. 1 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No.1 exceeds the rate determined by the formula: [§2104.02.a.3]

   \[ A = \sum x_i a_i \]

   Where:  
   
   - \( A \) = allowable emissions in pounds per million BTUs of actual heat input,  
   
   - \( i \) = fuel type (i.e. natural gas and coke oven gas),  
   
   - \( x_i \) = fraction of total actual heat input in BTUs provided by fuel type \( i \), and  
   
   - \( a_i \) = allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

   
e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 1, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 1, shall not exceed the limitations specified in Table V-K-1 below, at any time: [§2104.03, §2104.02.b, §2105.21.h.4]

Table V-K-1 - Boiler No. 1 Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.64</td>
<td>1.60</td>
<td>6.99</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.64</td>
<td>1.60</td>
<td>6.99</td>
</tr>
<tr>
<td>NOx</td>
<td>7.98</td>
<td>12.77</td>
<td>55.92</td>
</tr>
<tr>
<td>CO</td>
<td>7.71</td>
<td>3.38</td>
<td>33.76</td>
</tr>
<tr>
<td>VOC</td>
<td>0.51</td>
<td>0.22</td>
<td>2.21</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

g. SO₂ emissions from Boiler No. 1 shall not exceed the limitations in Table V-K-2 below: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]

Table V-K-2
SO₂ Emission Limitations for Boiler 1

<table>
<thead>
<tr>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.88</td>
<td>8.92</td>
<td>34.51</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:

a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.K.1.g, Table V-K-2 above. [SO₂ SIP IP 0050-1008, Condition V.A.2.b §2103.12.h]

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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §2103.12.h.5.B; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.K.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current
operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.K.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258, §2105.06, and §2103.12.j; 40 CFR 63, Subpart DDDDD; 25 PA Code §129.100]

   1) The date of the annual tune-up;
   2) The name of the service company and/or individuals performing the annual tune-up;
   3) The operating rate or load after the annual tune-up;
   4) The CO and NOx emission rate before and after the annual tune-up; and
   5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly, 12-month rolling totals of the following data for Boiler no. 1: [SO2 SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

   1) Fuel type, fuel usage, hours of operation and sulfur concentration expressed as H2S in grain per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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; 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report the concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.K.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 1 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No. 258; 25 PA Code §129.99]

   1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

   2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and
3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. Additional Requirements:

None except as provided elsewhere

PERMIT SHIELD IN EFFECT
L. Boiler No. 2

**Process Description:** One 84.6 MMBTU/hr natural gas and coke oven gas fired boiler

**Facility ID:** B002

**Max. Design Rate:** 84.6 MMBtu/hr

**Capacity:** 84.6 MMBtu/hr

**Raw Materials:** Coke oven gas and natural gas

**Control Device:** NA

1. **Restrictions:**

   a. Only coke oven gas and natural gas shall be combusted in Boiler No. 2. [2102.04.b.5]

   b. The permittee shall not operate, or allow to be operated Boiler No. 2 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 1 exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   c. The permittee shall not operate, or allow to be operated Boiler No. 2 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]

   d. The permittee shall not operate or allow to be operated Boiler No. 2 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No. 2 exceeds the rate determined by the formula: [§2104.02.a.3]

      \[
      A = \sum x_i a_i \quad \text{where } A = \text{allowable emissions in pounds per million BTUs of actual heat input},
      \]

      \[
      i = \text{fuel type (i.e. natural gas and coke oven gas)},
      \]

      \[
      x_i = \text{fraction of total actual heat input in BTUs provided by fuel type } i, \text{ and}
      \]

      \[
      a_i = \text{allowable emissions in pounds per million BTUs of actual heat input for fuel type } i, \text{ where } a_i = 0.008 \text{ for natural gas and } 0.02 \text{ for coke oven gas.}
      \]

   e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 2, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 2, shall not exceed the limitations in Table V-L-1 below, at any time: [§2104.03, §2104.02.b, §2105.21.h.4]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.68</td>
<td>1.69</td>
<td>7.41</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.68</td>
<td>1.69</td>
<td>7.41</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.05</td>
<td>18.20</td>
<td>45.90</td>
</tr>
<tr>
<td>NOx</td>
<td>8.46</td>
<td>13.54</td>
<td>59.29</td>
</tr>
<tr>
<td>CO</td>
<td>8.17</td>
<td>3.58</td>
<td>35.80</td>
</tr>
<tr>
<td>VOC</td>
<td>0.54</td>
<td>0.23</td>
<td>2.37</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

Table V-L-2 - Boiler No. 2 Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>30 day rolling average limit (lb/hr)*</th>
<th>Supplementary 24-hr Limit* (lb/hr)</th>
<th>Tons/year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>8.36</td>
<td>9.46</td>
<td>36.62</td>
</tr>
</tbody>
</table>

*Limits are based on a rolling 30-day average of 24-hour (calendar day) averages, with an additional restriction of no more than 3 consecutive days above a supplementary 24-hour limit. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

**Tons/year value is used to demonstrate the expected tons/year from this unit. The value is derived by converting the 30-day rolling average limit lb/hr to an annual tons per year value. These limits are based on ACHD’s SO₂ State Implementation Plan (SIP) Permit Revision and USEPA SO₂ Guidance dated September 14, 2017.

2. Testing Requirements:

a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition V.L.1.g, Table V-L-2 above. [SO₂ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]

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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains/gr/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.L.3.a
above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.L.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart D; 25 PA Code §129.100]

1) The date of the annual tune-up;
2) The name of the service company and/or individuals performing the annual tune-up;
3) The operating rate or load after the annual tune-up;
4) The CO and NOₓ emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler No. 2: [SO₂ SIP IP 0050-1008, Condition V.A.3; §2103.12.h.5.B]

1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H₂S in grains per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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; 25 PA Code §129.100]

5. Reporting Requirements:

a. The permittee shall report the concentration of H₂S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with General III.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO₂ SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.L.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 2 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258; 25 PA Code §129.99]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOₓ, and to the extent practicable minimize emissions of carbon monoxide.
(hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
M. Boiler No. 3

**Process Description:** One 41.6 MMBTUs/Hr natural gas and coke oven gas fired boiler

**Facility ID:** B003

**Max. Design Rate:** 41.6 MMBtu/hr

**Capacity:** 41.6 MMBtu/hr

**Raw Materials:** Coke oven gas and natural gas

**Control Device:** NA

1. **Restrictions:**
   a. Only coke oven gas and natural gas shall be combusted in Boiler No. 3. [2102.04.b.5]
   b. The permittee shall not operate, or allow to be operated Boiler No. 3 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 1 exceeds 0.008 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   c. The permittee shall not operate, or allow to be operated Boiler No. 3 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   d. The permittee shall not operate or allow to be operated Boiler No. 3 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No.3 exceeds the rate determined by the formula: [§2104.02.a.3]

   \[ A = \sum x_i a_i \]

   Where \( A \) = allowable emissions in pounds per million BTUs of actual heat input,

   \( i = \) fuel type (i.e. natural gas and coke oven gas),

   \( x_i = \) fraction of total actual heat input in BTUs provided by fuel type \( i \), and

   \( a_i = \) allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.

   e. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 3, 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. [§2105.21.h.4]
f. Emissions from Boiler No. 3, shall not exceed the limitations specified in Table V-M-1 below, at any time: [§2104.03, §2104.02.b, §2105.21.h.4]

Table V-M-1 - Boiler No. 3 Emission Limitations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>NOx</td>
<td>4.16</td>
<td>6.66</td>
<td>29.15</td>
</tr>
<tr>
<td>CO</td>
<td>4.02</td>
<td>1.76</td>
<td>17.60</td>
</tr>
<tr>
<td>VOC</td>
<td>0.26</td>
<td>0.11</td>
<td>1.15</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period

g. SO₂ emission from Boiler No. 3 (aggregate) shall not exceed the limitations in condition IV.26.c above: [§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b]

2. Testing Requirements:

a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition IV.26.c, Table IV-1 above. [SO₂ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h]

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 §2108.02. (§2103.12.h.1)

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes. [SO₂ SIP IP 0050-1008, Condition V.A.3; §§2103.12.h.5.B; §2103.12.i]

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.M.3.a V.E.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.M.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant. (0050-1006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment: [RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart DDDDD]

1) The date of the annual tune-up;
2) The name of the service company and/or individuals performing the annual tune-up;
3) The operating rate or load after the annual tune-up;
4) The CO and NOx emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler No. 3: [SO2 SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H2S in grains per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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 concentration of H2S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with GeneralIII.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO2 SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.M.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 3 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimizes emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. Additional Requirements:

None except as provided elsewhere.

PERMIT SHIELD IN EFFECT
N. Boiler No. 4

Process Description: One 41.6 MMBTUs/Hr natural gas and coke oven gas fired boiler
Facility ID: B004
Max. Design Rate: 41.6 MMBtu/hr
Capacity: 41.6 MMBtu/hr
Raw Materials: Coke oven gas and natural gas
Control Device: NA

1. Restrictions:
   a. Only coke oven gas and natural gas shall be combusted in Boiler No. 4. [2102.04.b.5]
   b. The permittee shall not operate, or allow to be operated Boiler No. 4 fueled entirely by Natural Gas in such a manner that the emissions of particulate matter from Boiler No. 4 exceeds 0.008 lbs./MMBTU of actual heat input, at any time or Boiler No. 4 fueled entirely by Coke Oven Gas in such a manner that the emissions of particulate matter exceed 0.02 lbs./MMBTU of actual heat input, at any time. [§2104.02.a.1]
   c. The permittee shall not operate or allow to be operated Boiler No. 4 fueled with Natural Gas and Coke Oven Gas, in such a manner that the emissions of particulate matter from Boiler No. 4 exceed the rate determined by the formula: [§2104.02.a.3]

   \[ A = \sum x_i a_i \]

   Where: A = allowable emissions in pounds per million BTUs of actual heat input,
   \( i \) = fuel type (i.e. natural gas and coke oven gas),
   \( x_i \) = fraction of total actual heat input in BTUs provided by fuel type \( i \), and
   \( a_i \) = allowable emissions in pounds per million BTUs of actual heat input for fuel type \( i \), where \( a_i = 0.008 \) for natural gas and 0.02 for coke oven gas.
   d. The permittee shall not flare, mix or combust coke oven gas, or allow such gas to be flared, mixed, or combusted in Boiler No. 4, 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. [§2105.21h.4]
e. Emissions from Boiler No. 4, shall not exceed the limitations specified in Table V-N-1 below, at any time:  
§2104.03, §2104.02.b, §2105.21.h.4

<table>
<thead>
<tr>
<th>POLLUTANT</th>
<th>lbs/hr (natural gas)</th>
<th>lbs/hr (coke oven gas)</th>
<th>tons/yr ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Particulate</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>PM-10</td>
<td>0.33</td>
<td>0.83</td>
<td>3.64</td>
</tr>
<tr>
<td>NOx</td>
<td>4.16</td>
<td>6.66</td>
<td>29.15</td>
</tr>
<tr>
<td>CO</td>
<td>4.02</td>
<td>1.76</td>
<td>17.60</td>
</tr>
<tr>
<td>VOC</td>
<td>0.26</td>
<td>0.11</td>
<td>1.15</td>
</tr>
</tbody>
</table>

¹ A year is defined as any consecutive 12-month period.

f. SO₂ emission from Boiler No. 4 (aggregate) shall not exceed the limitations in condition IV.26.c above:  
§§2105.21.h; SO₂ SIP IP 0050-1008, Condition V.A.1.b

2. Testing Requirements:

a. Emissions of SO₂ shall be determined by converting the H₂S grain loading of the fuel burned and the fuel flow rate, to pounds per hour to determine compliance with the emission limitations in condition IV.26.c, Table IV-1 above.  
SO₂ SIP IP 0050-1008, Condition V.A.2.b; §2103.12.h

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 §2108.02.  
§2103.12.h.1

3. Monitoring Requirements:

a. Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee shall continuously monitor and record the H₂S concentration (in grains(gr)/100 dscf) of the COG combusted and the fuel flow rate required in Site Level Condition IV.26.b. Continuously shall be defined as at least once every 15 minutes.  
SO₂ SIP IP 0050-1008, Condition V.A.3;  
§2103.12.h.5.B; §2103.12.i

b. Measurements of hydrogen sulfide concentrations in coke oven gas required in condition V.N.3.a above shall be conducted according to Section §2107.08 of Article XXI. Under the current operating scenario coke oven gas measurements are taken at the Clairton Plant, and these measurements will satisfy condition V.N.3.a. However, if there is a change to the current operating scenario, the sulfur concentration will be taken at the Irvin Plant.  
(0050-I006, Condition V.A.3; §2103.12.h.5.B)

4. Record Keeping Requirements:

a. The permittee shall maintain the following records of the annual tune-up for the subject equipment:  
RACT Order No.0258 and §2103.12.j; 40 CFR 63, Subpart DDDDD

1) The date of the annual tune-up;
2) The name of the service company and/or individuals performing the annual tune-up;
3) The operating rate or load after the annual tune-up;
4) The CO and NO\textsubscript{x} emission rate before and after the annual tune-up; and
5) The excess oxygen rate after the annual tune-up.

b. The permittee shall maintain hourly, monthly and 12-month rolling totals of the following data for Boiler no. 4: [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.4.a; §2103.12.h.5.B]

1) Fuel type (COG and natural gas), fuel usage, hours of operation and sulfur concentration expressed as H\textsubscript{2}S in grain per 100 dscf in coke oven gas used for combustion, for the subject boiler.

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 concentration of H\textsubscript{2}S per 100 dscf of COG averaged over a calendar day to the Department on a quarterly basis, in accordance with GeneralIII.15.e. All instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance shall be reported. [SO\textsubscript{2} SIP IP 0050-1008, Condition V.A.5.a; §2103.12.k]

b. Reporting instances of non-compliance in accordance with V.N.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

a. The permittee shall perform an annual adjustment or "tune-up" on Boiler No. 4 once every twelve (12) months, (hereafter referred to as "annual tune-up"). Such annual tune-up shall include: [RACT Order No.0258]

1) Inspection, adjustment, cleaning, or necessary replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NO\textsubscript{x}, and to the extent practicable minimize emissions of carbon monoxide (hereafter referred as "CO"); and

3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

7. Additional Requirements:

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
O. Fugitive Particulate Emissions From Roads and Vehicles

Process Description: Approximately 3.23 miles of paved roads, approximately 0.85 miles of unpaved roads, and approximately 4.3 acres of parking areas.

Facility ID: F001

1. Restrictions:
   a. The permittee shall apply a chemical dust suppressant to the entire surface of all unpaved parking areas in use on the west side of the plant and on all unpaved roads at appropriate rates and intervals of time to maximize dust suppression and comply with Site Level Conditions IV.18, IV.19 and IV.23 above. [§2105.40, §2105.42 and §2105.49]
   b. The permittee shall comply with the following conditions for the paved road from the railroad trestle to the loading dock at the Irvin Plant and any paved road and paved areas at the coal storage area at the Irvin Plant to comply with Site Level Conditions IV.18, IV.19 and IV.23 above. [§2105.40, §2105.42 and §2105.49]

   1) Properly maintain, repair, patch and repave all paved roads and areas.

2. Testing Requirements:
   None except as provided elsewhere.

3. Monitoring Requirements:
   None except as provided elsewhere.

4. Record Keeping Requirements:
   a. The permittee shall record or have access to records that list the date, time, amount of undiluted chemical dust suppressant and the dilution ratio of each application of chemical dust suppressant. [§2103.12.j]

5. Reporting Requirements:
   a. The permittee shall prepare a report within 30 days of each calendar quarter, in accordance with General Condition III.15.e, that includes: [§2103.12.k]

   1) An identification of any maintenance, repairs, patching or repaving of the paved roads or areas.
   2) The dates on which chemical dust suppressant was applied, and for each date, the location(s) and the dilution ratio(s) of the application.

   b. The permittee shall report to the Department every six months, in accordance with General Condition III.15.d above, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]

   c. Reporting instances of non-compliance in accordance with Conditions V.O.5.a and V.O.5.b above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standard:
None except as provided elsewhere.

7. **Additional Requirements:**

None except as provided elsewhere.

**PERMIT SHIELD IN EFFECT**
P. Solvents Parts Cleaning

Process Description: Solvents parts cleaning for maintenance.
Facility ID: F002

1. Restrictions:
   a. The permittee shall maintain all cleaning solvents containing volatile organic compounds in closed containers at all times except when in use. [§2103.12.a.2.B]
   
   b. The permittee shall clean any spilled cleaning solvent that contains volatile organic compounds as expeditiously as possible. [§2103.12.a.2.B]
   
   c. The emissions from parts solvent cleaning shall not exceed 30 tons/year of volatile organic compounds or 1.0 tons of hazardous air pollutants.
   
   d. The permittee shall not operate, or allow to be operated, any cold cleaning degreaser with a degreaser opening exceeding ten (10) square feet, unless [§2105.15.a]:
      
      1) There is in operation on such degreaser:
         i. A cover to prevent evaporation of solvent during periods of non-use;
         ii. Equipment for draining cleaned parts; and
         iii. A permanent conspicuous label summarizing the operating requirements set forth in Paragraph V.P.1.d.2) below; and
      
      2) Such degreaser is operated at all times in such manner that:
         i. Waste solvents are transferred to another party or disposed of by means insuring that no more than 20% by weight of the solvents evaporate into the open air;
         ii. Waste solvents are stored in covered containers;
         iii. The degreaser cover is closed when parts are not being processed through the degreaser; and,
         iv. Cleaned parts are drained for at least 15 seconds or until dripping ceases.
   
   e. Compliance with the above VOC and HAP emission limitations shall be determined by accepted mass balance methodology applied to records of solvent usage and recovery. A year shall be defined as any 12 consecutive months for the above emission limitations. [§2103.12.5.B]

2. Testing Requirements:

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

3. Monitoring Requirements:

None except as provided elsewhere.

4. Record Keeping Requirements:

a. The permittee shall maintain records of the type of cleaning solvent used, the pounds of VOC per gallon of the solvent, the amount purchased and the amount disposed of for each cleaning solvent containing volatile organic compounds sufficient to demonstrate compliance with the above
emission limitations by Condition V.P.1.e above. These records shall be compiled on a 12 month rolling total basis. [§2103.12.h.5.B]

b. 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 to the Department every six months, in accordance with General Condition III.15.d, all instances of non-compliance with the conditions of this permit along with all corrective action taken to restore the subject equipment to compliance. [§2103.12.k]

b. Reporting instances of non-compliance in accordance with Condition V.P.5.a above, does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.7 above, if appropriate. [§2103.12.k]

6. Work Practice Standards:

None except as provided elsewhere.

7. Additional Requirements:

None except as provided elsewhere

PERMIT SHIELD IN EFFECT
VI. ALTERNATIVE OPERATING SCENARIOS

No alternative operating scenarios exist for this facility

PERMIT SHIELD IN EFFECT
VII. MISCELLANEOUS

PERMIT SHIELD IN EFFECT
VIII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the estimated annual maximum potential emissions, including the four flares from the U. S. Steel Mon Valley Works - Irvin Plant. These annual (consecutive 12 month) emission estimates assume that all sources operate continuously at their maximum capacity.

<table>
<thead>
<tr>
<th>POLLUTANT</th>
<th>tons/year $^1$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate</td>
<td>123.89</td>
</tr>
<tr>
<td>PM-10</td>
<td>124.52</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>1,248.74</td>
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<tr>
<td>NO$_x$</td>
<td>749.15</td>
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<tr>
<td>CO</td>
<td>1,179.08</td>
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<tr>
<td>VOC</td>
<td>203.99</td>
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<tr>
<td>Lead</td>
<td>0.08</td>
</tr>
<tr>
<td>Hydrochloric Acid</td>
<td>36.77</td>
</tr>
</tbody>
</table>

$^1$A year is defined as any consecutive 12-month period.