

**Boling, Jean**

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**From:** Michael Bean (revbean@sbcglobal.net) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:51 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

Dear Jean Boling,

IDEM must reduce and limit the amount of sulfur dioxide and nitrogen oxides that are currently released into the environment and atmosphere. IDEM must require increased regulation and monitoring of sulfur dioxide and nitrogen oxides emission rates.

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Michael Bean  
601 S EISENHOWER DR  
EDINBURGH, IN 46124  
revbean@sbcglobal.net  
(812) 526-9270

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Jim Sweeney (jp55biod@att.net) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:44 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

Your job is to provide us clean air, not air that is clean enough to keep the factories open. Make them clean their messes up.

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Jim Sweeney  
1773 Selo Dr  
Schererville, IN 46375  
jp55biod@att.net  
(219) 379-7989

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Richard Hill (rhill@cinergymetro.net) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:41 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

I have visited national parks in the region including Mammoth Cave and the Smokey Mountains. I would like to see them and others maintain clean natural views and healthy breathable air. I also live about 2 miles from IKEC'S Clifty Creek power station and would urge IDEM to comply with the pollution reduction requirements

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Richard Hill  
230 SOUTH PAINE STREET  
HANOVER, IN 47243  
rhill@cinergymetro.net  
(812) 801-3221

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Susan Thomas (sthom1113@gmail.com) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:31 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

Dear Jean Boling,

I live within the National Park, surrounded by toxic industrial pollution to air, land and water. Photosynthesis is disrupted by air pollution/haze and our native plant population here contributes to the unique ecosystem/food chain that cannot be damaged further!

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Susan Thomas  
215 S. Broadway  
Beverly Shores, IN 46301  
sthom1113@gmail.com  
(847) 767-1870

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.



**Boling, Jean**

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**From:** nathan pate (socomfy@gmail.com) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:24 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

nathan pate  
1401 W County Road 840 S  
Paoli, IN 47454  
socomfy@gmail.com  
(812) 666-4003

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at [amanda.shepherd@sierraclub.org](mailto:amanda.shepherd@sierraclub.org) or (317) 822-3750.

**Boling, Jean**

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**From:** John Oberlies (oberliesj@gmail.com) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:24 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

John Oberlies  
9012 Colgate St  
Indianapolis, IN 46268  
oberliesj@gmail.com  
(317) 431-0851

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Katherine Kiang (kathk15@gmail.com) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:18 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health; and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Katherine Kiang  
403 W Vermont St  
Indianapolis, IN 46202  
kathk15@gmail.com  
(331) 643-0571

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at [amanda.shepherd@sierraclub.org](mailto:amanda.shepherd@sierraclub.org) or (317) 822-3750.

**Boling, Jean**

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**From:** Ben Novoa III (ben9833@att.net) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:12 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

Dear Jean Boling,

Please strengthen your Regional Haze Plan since it fails to impose any pollution reductions on polluters. Please do your job to protect the environment. Environmental Management is in your name but you need to do it to benefit the people of the state of Indiana and not Indiana's polluting companies. Grow a backbone and stand up to Indiana's polluters.

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Ben Novoa III  
6901 east 112 avenue  
Crown Point, IN 46307  
ben9833@att.net  
(219) 577-7109

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Mary C Tanner (mcctanner@sbcglobal.net) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:11 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

Dear Jean Boling,

Every action we take...or fail to take...impacts our environment and our children's future.

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Mary C Tanner  
6635 Avila Way  
Fishers, IN 46038  
mcctanner@sbcglobal.net  
(317) 514-2194

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

---

**From:** Wendy Bredhold (wendybredhold@gmail.com) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 4:00 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Wendy Bredhold  
3307 E. Chandler Ave.  
Evansville, IN 47714  
wendybredhold@gmail.com  
(812) 604-1723

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Julia Lowe (J\_lowe66@yahoo.com) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 3:46 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

Dear Jean Boling,

I ask that the state of Indiana regulations require polluters to reduce harmful air pollution and protect visibility. It is the commitment to actions like this that will improve our bleak outlook. Please take steps to protect Hoosiers from fossil fuel polluters and dirty industry. If not today when? Thank you, Julie Lowe.

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Julia Lowe  
3615 Saddle Drive  
COLUMBUS, IN 47203  
J\_lowe66@yahoo.com  
(317) 345-8355

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** Jesse Kirkham (jlkirkham@earthlink.net) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 3:37 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Jesse Kirkham  
370 Kaymar Drive  
Danville, IN 46122  
jlkirkham@earthlink.net  
(317) 745-7795

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.



**Boling, Jean**

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**From:** Clem, Ryan T  
**Sent:** Monday, October 25, 2021 2:54 PM  
**To:** DELONEY, SCOTT; Boling, Jean; DERF, MARK; Bem, Susan; Stuckey, Matt (IDEM)  
**Cc:** Rockensuess, Brian; Moorhous, Erin; IDEM Media  
**Subject:** Sierra Club: Tell IDEM to Hold Polluters Accountable

FYI

<https://addup.sierraclub.org/campaigns/tell-idem-to-hold-polluters-accountable>

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**Official Hoosier Chapter Campaign**

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# **Tell IDEM to Hold Polluters Accountable**

The Indiana Department of Environmental Management is seeking comments on its draft regional haze plan, a do-nothing plan that fails to impose any pollution reductions on any polluters.

## **Why This Matters**

The goal of the regional haze part of the Clean Air Act is to protect visibility at our national parks. Mammoth Cave in Kentucky is the national park most impacted by Indiana polluters, but of course Hoosiers are impacted by their pollution too. The same types of pollution that cause haze--sulfur dioxide and nitrogen oxides/ozone--also cause serious public health problems. In this draft plan, IDEM has failed to reduce harmful air pollution from Duke's Gibson County Super Polluter, US Steel in Gary, and Alcoa Warrick's high polluting aluminum plant in Warrick County, among others. IDEM's whole plan is designed to defend not requiring anything from Indiana polluters.

Get Started - Send the Email below, using the listed subject line and adding a personal message!

Subject: Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

To: Jean Boling at IDEM - [jboling@idem.IN.gov](mailto:jboling@idem.IN.gov)

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.



Celebrating Thirty-Five  
Years of Protecting  
Hoosiers and Our  
Environment

Ryan T. Clem  
Director of Communications

(317) 233-4927 • [rclem@idem.IN.gov](mailto:rclem@idem.IN.gov)

IDEM values your feedback.  
Please take two minutes and complete this brief survey.



[Facebook](#) | [LinkedIn](#) | [Twitter](#) | [YouTube](#) | [www.idem.IN.gov](#)

**From:** Critical Mention <[alert@criticalmention.com](mailto:alert@criticalmention.com)>  
**Sent:** Monday, October 25, 2021 2:11 PM  
**To:** IDEM Media <[media@idem.in.gov](mailto:media@idem.in.gov)>  
**Subject:** Indiana Department of Environmental Management Alert: Tweet from E ...

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You're always on it with Critical Mention.

## Indiana Department of Environmental Management new mention

**E Scrafford**



**Handle** @dayswithe  
**User Location** Central IL



**Date Collected** Oct 25, 2021 02:11 PM EDT

**Followers** 1,693

**Retweets** 1

RT @HoosierChapter: The Indiana Department of Environmental Management is seeking comments on its draft regional haze plan, a do-nothing plan that fails to impose any pollution reductions on polluters. Take action today! <https://t.co/KcRWtkKO8x>

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Our mailing address is:

Critical Mention  
19 W 44th Street  
New York, NY 10036

**Boling, Jean**

---

**From:** Amanda Shepherd (amanda.shepherd@sierraclub.org) Sent You a Personal Message  
<kwautomail@phone2action.com>  
**Sent:** Monday, October 25, 2021 2:06 PM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Amanda Shepherd  
4305 Glencairn Ln  
Indianapolis, IN 46226  
amanda.shepherd@sierraclub.org  
(317) 476-2170

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.

**Boling, Jean**

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**From:** heather leslie <miss.ellaney@yahoo.com>  
**Sent:** Thursday, October 21, 2021 9:54 AM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Hi,  
I live with my family in New Albany, IN and we are impacted by living in some of the dirtiest air in our nation. Around here, asthma is the norm. As a jogger, I have to check daily air quality and it often is not Fair or Good.

Now is the time to protect Americans' health and at the same time improve our ability to recreate outside in our neighborhoods and in designated parks. The pollution creating haze and bad air quality is also impacting climate change. We face flooding, increased pests (ticks & mosquitos) and long, bad allergy seasons because of climate change here in Southern IN.

I encourage IDEM and the US EPA to apply the law and reduce air pollution from Indiana sources.

Heather Swinney  
1606 Hedden Park  
New Albany, IN  
47150

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## Appendix Y

### **Affected Sources**

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**Boling, Jean**

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**From:** Blahut, Jacob N <jnblahut@uss.com>  
**Sent:** Monday, November 15, 2021 7:35 PM  
**To:** Boling, Jean  
**Cc:** Piscitelli, Alexis S; Hanning, Joseph E  
**Subject:** USS Gary Works Comments - Regional Haze SIP  
**Attachments:** USS Gary Works Comments - Indiana Regional Haze SIP 11-15-2021.pdf

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Dear Ms. Boling,

Please see attached for USS Gary Works' comments for the Regional Haze SIP.

Thank you,  
Jacob Blahut  
Air Compliance Manager | Environmental Control  
United States Steel Corporation, Gary Works  
(219) 888-3432 – office  
(219) 314-4315 – cell

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United States Steel Corporation  
Gary Works  
One North Broadway  
Gary, IN 46402-3199

November 15, 2021

**Via Electronic Mail**

Ms. Jean Boling  
Indiana Department of Environmental Management  
Office of Air Quality, Room 1003  
100 North Senate Avenue  
Indianapolis, Indiana 46204  
JBoling@idem.in.gov

**Subject: U. S. Steel - Gary Works Comments on Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period**

Dear Ms. Boling:

United States Steel Corporation (U. S. Steel) – Gary Works appreciates the opportunity to submit the following comments in support of the Indiana Department of Environmental Management (IDEM)'s proposed Indiana Regional Haze State Implementation Plan (SIP) for the Second Implementation Period.

U. S. Steel supports IDEM's conclusions that (1) none of the controls identified in the four-factor analyses were cost effective for the small amount of emission reductions that would be realized, and (2) Indiana has demonstrated that visibility improvements for this second implementation period for regional haze is well ahead of reasonable progress goals.

U. S. Steel reaffirms IDEM's conclusions based on the following information previously provided by Gary Works during the four-factor analysis evaluation:

- Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors. Therefore, installation of additional emission controls at Gary Works will not appreciably improve visibility in these Class I areas.
- The trajectory analysis included in Gary Works' Four-Factor Analysis report considered the 20% most impaired trajectories for each Class 1 area based on 2017 and 2018 IMPROVE data. Of 137 most impaired days, only 2.5%, or 3.5 days out of 137, of the most impaired trajectories cross near Gary Works; in fact, the majority of the most impaired trajectories are not even traveling from the general direction of Gary Works. Furthermore, most of the 48-hour reverse trajectories end before reaching Gary, IN, indicating that the nearest Class I areas are far enough away from Gary Works that visibility impairment caused by Gary Works is unlikely. As such, the installation of additional emission control measures at Gary Works would not improve visibility in these Class I areas.
- The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below (Mammoth Cave and Seney), or trending towards (Mingo), the 2028 URP.



United States Steel Corporation  
Gary Works  
One North Broadway  
Gary, IN 46402-3199

- As shown in the Gary Works Four-Factor Analysis report, the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals; the 5-year average visibility impairment on the most impaired days is already below the 2028 URP at two of the Class I areas which were considered (Mammoth Cave and Seney). In addition, the 5-year visibility impairment at the third Class I area (Mingo) is only slightly above the 2028 URP (20.2 dV observed versus 19.6 dV for the 2028 URP) and has been trending downward since 2007. Therefore, it is unnecessary for Gary Works to install additional emission control measures to make reasonable progress at these Class I areas.

U. S. Steel – Gary Works supports IDEM’s conclusions that no action is needed in Indiana to make reasonable progress on visibility in Class 1 Areas. Please contact Joe Hanning at [JEHanning@uss.com](mailto:JEHanning@uss.com) or (219) 888-4500 with questions.

Sincerely,

A handwritten signature in black ink, appearing to read "Jacob Blahut", with a long, sweeping horizontal line extending to the right.

Jacob Blahut  
Air Compliance Manager | Environmental Control  
United States Steel Corporation

**Boling, Jean**

---

**From:** Ferguson, Michelle <Michelle.Ferguson@buzziunicemusa.com>  
**Sent:** Monday, November 15, 2021 6:06 PM  
**To:** Boling, Jean  
**Cc:** miriam.press@buzziunicemusa.com; Paul Schell  
**Subject:** Buzzi Unicem USA Comments on IDEM SIP Regional Haze  
**Attachments:** BUUSA Comment Draft Regional Haze SIP 2IP.pdf

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Good evening Jean

Please find Buzzi Unicem comments regarding IDEM's Draft Regional Haze SIP Second Implementation Period.

Regards

Michelle  
Michelle Ferguson  
Director, Environmental Affairs  
Buzzi Unicem USA  
1000 River Cement Rd.  
Festus, MO 63028

Ph: 636.931.2504  
Cell: 314.852.8434



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Ms. Jean Boling  
Indiana Dept of Environmental Management  
Office of Air Quality, Room 1003  
100 North Senate Avenue  
Indianapolis, IN 46204

**Buzzi Unicem USA Comments on Draft  
Regional Haze SIP for the Second  
Implementation Period**

November 15, 2021

Dear Ms. Boling:

Buzzi Unicem USA (Buzzi) has reviewed Indiana's draft Regional Haze State Implementation Plan (SIP) for the Second Implementation Period. As you are aware, the Buzzi Greencastle Plant was one of the portland cement kilns that was considered in IDEM's evaluation of the cement kiln source category for the four-factor analysis. Buzzi appreciates this opportunity to comment on the draft SIP and includes the enclosed comments for your consideration.

If you have any questions on the enclosed comments, please feel free to contact me at 636.931.2504 ([michelle.ferguson@buzziunicemusa.com](mailto:michelle.ferguson@buzziunicemusa.com)) or Miriam Press at 765.653.9766 x3122 ([Miriam.Press@buzziunicemusa.com](mailto:Miriam.Press@buzziunicemusa.com)).

Sincerely,



*Michelle Ferguson*

Michelle Ferguson  
Director, Environmental Affairs

Attachment

cc:  
Miriam Press  
Timothy Menke  
Paul Schell

## Buzzi Unicem USA Comments on Indiana Draft Regional Haze State Implementation Plan

Citation	Citation Text	Comment
<p>Section 10, Table 10-3, Pg 104</p>	<p>IDEM identifies various control technologies, including:</p> <p>Conventional Dry Flue Gas Desulfurization (FGC) – Dry Sorbent Injection</p> <p>Conventional Dry Flue Gas Desulfurization (FGD) – Spray Dryer</p> <p>Advanced Flue Gas Desulfurization (FGD)</p>	<p>Buzzi believes the descriptions for the technologies are incorrect, and should match the text descriptions that follow in Section 10.4.1.</p> <p>For example, the table describes the Conventional Dry Flue Gas Desulfurization (FGD) – Dry Sorbent Injection is described as “An absorbent reagent such as lime slurry is introduced into the flue gas stream through direct injection to absorb SO<sub>2</sub>, creating a dry solid which is caught in a downstream fabric filter or ESP”</p> <p>This should reflect the use a dry sorbent material, rather than a slurry. The descriptions for all three technologies should be corrected in order prevent further incorrect citations.</p>
<p>Appendix G, Section 3.1, Table 3-1, Pg 5</p>	<p>IDEM identifies various control performance characteristics with citation to resources, including the following:</p> <p>Mid-Kiln Firing: 10-55% reduction in NO<sub>x</sub></p> <p>SNCR: 45% reduction in NO<sub>x</sub></p> <p>SCR: 90% reduction in NO<sub>x</sub></p>	<p>The citations used to support performance characteristics for the identified technologies are dated, are not applicable to all cement kiln types, and may not be technically feasible. Specifically, the upper end of range associated with mid-kiln firing is unrealistically high for any modern kiln. The reference cited for SNCR shows a 30% maximum performance and is a document from 2008, yet 45% is stated in Appendix G. More recent EPA documents suggest a median reduction of 40% in cement kilns. See EPA’s Cost Control Manual, Section 4, NO<sub>x</sub> Controls, Chapter 1 (updated 4/25/2019).</p> <p>SCR has shown to be technically infeasible for numerous lime and cement kilns and should not be identified at all, and certainly not with an estimated NO<sub>x</sub> reduction attributed to it.</p>

Citation	Citation Text	Comment
Appendix G, Section 3.1.2, Pg 8	SCR NOx reduction observed ranges from 70 to 90 percent.	<p>SCR is not a viable control technology for a cement kiln. According to EPA's Cost Control Manual, Section 4 NOx, Chapter 2 SCR, June 2019, only one SCR has been installed on a cement kiln in the US. The control scheme discussed is unique and not representative of a cost-effective retrofit.</p> <p>Sections 3.1.2 and 3.2.1 discuss technological issues with SCR technology when applied to a cement kiln for NOx control, but does not state the technology is technically infeasible but rather provide cost estimates for the technology in Table 3-2. With only one installation in the US and the uniqueness of the application, Buzzi believes such information is misleading and any cost information presented must account for the entire process and equipment configuration (gas reheating, catalyst cleaning, etc) needed to support operation of a SCR system even if it was technically feasible.</p>
Appendix G, Section 3.2.1, Table 3-2, Pg 10	<p>IDEM presents various cost ranges for NOx controls regardless of feasibility and cites very low, lower-end range cost effectiveness and a single value for cost of SNCR as follows:</p> <p>LNB + Indirect: \$200-\$21,100/ton Mid-Kiln Firing:  \$600-\$3,600/ton SNCR:  \$1,400/ton  SCR: \$600-\$17,700/ton</p>	<p>Buzzi believes it misleading to present cost information for controls independent of kiln type, installation, etc. As presented the information is misleading. In addition, where a control technology is not feasible, such as SCR, installation costs should not be presented as they would need to consider many factors including the need for upstream/downstream controls and potentially reheating of flue gas for optimal catalytic reaction. Buzzi does not believe such considerations were included in the stated cost estimates. Control cost cited should have a breakdown akin to Appendix C. Region 8 Cement Kiln BART Analyses and Appendix P. Greencastle BART Control Analyses which are specific to the facility and variables associated with that installation.</p>



Citation	Citation Text	Comment
Appendix G, Section 3.3, Table 3-3, Pg 13	<p>IDEM has cited performance criteria for Advanced Flue Gas Desulfurization (AFGD) of 95-99.5% reduction in SO<sub>2</sub>. A 2005 LADCO analysis is cited. This is reiterated in Section 3.3.1 under AFGD.</p> <p>IDEM states in Section 3.3.1 for AFGD: AFGD has not been used in cement kilns before.</p> <p>AFGD is not generally considered technically feasible for cement kilns.</p>	<p>In general, AFGD is not considered technically feasible for cement kilns. Furthermore, it is unlikely the 99.5% reduction is supportable via the literature for a cement kiln and would, almost certainly, not be offered as a performance guarantee by a control technology vendor, especially if the technology has not been employed by any cement plant. Lastly, while IDEM states the technology is not technically feasible, Buzzi objects to IDEM providing control efficiency estimates as though it is technically feasible.</p>
Appendix G, Section 3.4.1, Table 3-4, Pg 17	<p>Similar to Table 3-2 for NO<sub>x</sub> controls, IDEM has presented cost ranges for SO<sub>2</sub> control technologies. Ranges are as follows:</p> <p>FGD – DSI: \$2,400-\$9,000/ton  FGD – Spray Dryer: \$2,300-\$88,800/ton  AFGD: \$2,400-\$47,100/ton  Wet FGD: \$1,500-\$78,800/ton</p>	<p>Buzzi believes it misleading to present cost information for controls independent of kiln type, installation, etc. As presented the information is misleading. Also, where a control technology is not feasible, such as AFGD, no cost information should be included as though it is feasible. Control cost cited should have a breakdown akin to Appendix C. Region 8 Cement Kiln BART Analyses and Appendix P. Greencastle BART Control Analyses which are specific to the facility and variables associated</p>

**Boling, Jean**

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**From:** Flynn, Aaron M. <aaronflynn@mcguirewoods.com>  
**Sent:** Monday, November 15, 2021 1:50 PM  
**To:** Boling, Jean  
**Subject:** Duke Energy Comments on Draft Indiana Regional Haze SIP  
**Attachments:** Duke Energy Comments on Indiana Regional Haze SIP.pdf

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Dear Ms. Boling,

Attached, please find the comments of Duke Energy on the Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period. Please get in touch if you have any questions.

Best,

Aaron Flynn  
Counsel for Duke Energy

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**Comments of Duke Energy on the  
Indiana Regional Haze State Implementation Plan  
for the Second Implementation Period**

November 15, 2021

Duke Energy welcomes this opportunity to comment on the Indiana Department of Environmental Management (“IDEM”) Draft Regional Haze State Implementation Plan for the Second Implementation Period (“Draft SIP”). IDEM is preparing this Draft SIP to satisfy the requirements of sections 169A and 169B of the Clean Air Act (“CAA” or the “Act”),<sup>1</sup> the United States Environmental Protection Agency’s (“EPA” or the “Agency”) regional haze rule (“RHR”),<sup>2</sup> and applicable guidance for the second planning period of the program (2018-2028).<sup>3</sup>

IDEM has prepared a well-supported plan for making reasonable progress toward the national visibility goal. The Draft SIP is consistent with the applicable laws and guidance, and it includes reasoned analysis to justify the state’s policy determinations. Duke Energy offers these comments in support of the Draft SIP and additional analysis to support IDEM’s Draft SIP. Duke Energy also welcomes the opportunity to continue to provide IDEM with data, analysis, and other technical support to help facilitate the SIP’s finalization.

**I. The Scope of State Discretion Under the Regional Haze Program Supports IDEM’s Draft SIP.**

The CAA’s regional haze program embodies the Act’s concept of cooperative federalism. EPA is tasked with setting the rules for the development of regional haze SIPs, and the CAA assigns responsibility for designing those SIPs to the states. Specifically, the statute and the RHR call on states to prepare SIPs that contain a long-term strategy for making reasonable progress and to develop reasonable progress goals (“RPGs”) for the Class I areas located within the state. States develop the measures to include in their long-term strategies by evaluating the four reasonable progress factors:

- The costs of compliance;
- The time necessary for compliance;
- The energy and nonair quality environmental impacts of compliance; and
- The remaining useful life of any existing source subject to such requirements.<sup>4</sup>

Indiana has expansive discretion in how it takes the four reasonable progress factors into account and in how to weigh and evaluate them. EPA’s rules and guidance require only that states satisfy the basic requirements of the Act and that the states’ analysis and decision-making be reasonable. These standards are intended to allow states considerable leeway in deciding how best to implement the regional haze program.

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<sup>1</sup> 42 U.S.C. §§ 7491, 7492.

<sup>2</sup> 40 C.F.R. § 51.308(f).

<sup>3</sup> See generally <https://www.epa.gov/visibility/visibility-guidance-documents>.

<sup>4</sup> 42 U.S.C. § 7491(g).

Some of the earliest court decisions addressing regional haze emphasized the primacy of the states in making regional haze decisions. In *American Corn Growers Association v. EPA*,<sup>5</sup> the U.S. Court of Appeals for the D.C. Circuit held that EPA could not limit the states' discretion over how to weigh factors under the program.<sup>6</sup> In reaching that conclusion, the court said that states "play the lead in designing and implementing regional haze programs," that "Congress directed states to make" the judgment as to how to weigh the factors, and that the 1999 version of the RHR was ultimately "inconsistent with the Act's provisions giving the states broad authority" over the program.<sup>7</sup>

In response, EPA has itself recognized state discretion to decide how to address regional haze. In its 1999 RHR, EPA emphasized that "flexibility for State discretion is, of course, exactly what the regional haze rule provides."<sup>8</sup> In its most recent revision to the RHR, the Agency similarly stated that "EPA has consistently interpreted the CAA to provide states with the flexibility to conduct four-factor analyses for specific sources ... depending on state policy preferences and the specific circumstances of each state."<sup>9</sup>

Recent EPA guidance reaffirms this state discretion. In its August 2019 Guidance, EPA explained that states have discretion to balance the four statutory factors and five additional considerations specified in the RHR in determining what control measures are necessary to make reasonable progress.<sup>10</sup> EPA's 2021 Guidance further explains that "while states have discretion to reasonably select sources, this analysis should ... ensure that source selection ... has the potential to meaningfully reduce their contributions to visibility impairment."<sup>11</sup>

IDEM has made appropriate and reasonable use of its discretion to develop its regional haze SIP for the second planning period of the program. The record contains extensive analysis and technical work, and the state has used that technical work to provide a reasoned analysis of the relevant issues, including a thorough explanation for its decisions regarding Duke Energy's facilities. Conducting this reasoned analysis is exactly what the CAA and the RHR require.

## **II. IDEM Has Reasonably Decided to Conduct a Reasonable Progress Analysis for EGUs as a Source Category.**

The Draft SIP explains that Indiana has determined that for the second planning period, four-factor analyses for electric generating units ("EGUs") are not an appropriate or effective use of state resources, and that it would be reasonable and more effective to instead focus on non-EGUs

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<sup>5</sup> 291 F.3d 1 (D.C. Cir. 2002).

<sup>6</sup> The decision addressed the five factors for assessing the program's best available retrofit technology ("BART") program, but it should be interpreted to apply with equal weight to the related reasonable progress factors.

<sup>7</sup> *Id.* at 2, 6, 8.

<sup>8</sup> 64 Fed. Reg. 35,714, 35,760 (July 1, 1999).

<sup>9</sup> 82 Fed. Reg. 3078, 3088 (Jan. 10, 2017).

<sup>10</sup> EPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, at 4 (Aug. 20, 2019) (hereinafter "2019 Guidance").

<sup>11</sup> EPA, *Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period*, at 3 (July 8, 2021) (hereinafter "2021 Guidance").

during the second planning period.<sup>12</sup> Nevertheless, IDEM conducted a “reasonable progress analysis” for the state’s EGUs.<sup>13</sup> The rationale IDEM provides for this decision is well-reasoned and consistent with the CAA and EPA Guidance. As the state explains, EGUs were evaluated “in great detail” during the first regional haze planning period and are subject to strict emission controls pursuant to regional haze and other air quality requirements. Many of those EGUs, including the Duke Energy facilities, as discussed in greater detail below, are subject to highly effective emission controls and have limited effects on visibility impairment. All of these considerations strongly support a conclusion that the EGU source category as a whole is unlikely to be a fruitful subject of additional regulation with regard to regional haze or that additional control requirements would be cost-effective or necessary for reasonable progress. Further, the state notes the significant changes occurring in the electric generating industry driving shifts to lower emitting or zero emitting generation, and that many of these changes are expected to occur over the next decade. Indeed, the Draft SIP points to many unit closures that are projected to occur during the second planning period. All of these factors support the state’s determination not to require additional controls or to conduct formal individualized four-factor analyses for EGUs at this time.

It is also lawful for the state to take this approach. EPA has long maintained that states need not conduct source-by-source reasonable progress assessments for all facilities and that source category-wide assessments can be reasonable.<sup>14</sup> The state has cited relevant portions of the 2019 Guidance to support its decision.<sup>15</sup> That guidance also lists a number of factors states can consider when making these decisions:

Factors could include but are not limited to baseline source emissions, baseline source visibility impacts (or a surrogate metric for the impacts), the in-place emission control measures and by implication the emission reductions that are possible to achieve at the source through additional measures, the four statutory factors (to the extent they have been characterized at this point in SIP development), potential visibility benefits (also to the extent they have been characterized at this point in SIP development), and the five additional required factors listed in 40 CFR 51.308(f)(2)(iv).<sup>16</sup>

The Draft SIP addresses each of these factors, and these comments provide additional information on many of them for the Duke Energy facilities in section III below.

The Draft SIP also explains that IDEM will conduct a review of the EGU sector as part of its January 31, 2025 progress report, pursuant to 40 CFR 51.308 (g).<sup>17</sup> Given the significant changes taking place within the sector, this is a reasonable approach to take with EGUs at this time. It is also entirely consistent with the requirements of the regional haze program.

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<sup>12</sup> Draft SIP at 223.

<sup>13</sup> *Id.*

<sup>14</sup> See Guidance for Setting Reasonable Progress Goals under the Regional Haze Program at 3-1 - 3-2 (2007); 2019 Guidance at 12, 34.

<sup>15</sup> Draft SIP at 45.

<sup>16</sup> 2019 Guidance at 10.

<sup>17</sup> Draft SIP at 45

Finally, comments from the Federal Land Managers (“FLMs”) state that it is not reasonable to exclude EGUs from individual four-factor analyses and that there may be cost-effective controls available for some EGUs.<sup>18</sup> Notably, the National Park Service (“NPS”) comments do not identify any of the Duke Energy units as units for which cost-effective controls might exist. The Forest Service comments call for a four-factor analysis for Gibson Generating Station for SO<sub>2</sub>, along with other EGUs. None of these comments, as summarized in Appendix U, provide a justification for such a requirement, nor do they attempt to counter the reasonable points made by IDEM in support of its position. The state’s response, repeating and expanding upon the points already included in the Draft SIP, more than adequately addresses these comments.

### **III. The State’s Determinations for Duke Energy’s Gibson, Cayuga, and Gallagher Generating Stations Are Reasonable.**

IDEM prepared a reasonable progress analysis using a weight-of-the-evidence approach for Duke Energy’s three coal-fired power plants in the state: the Gibson, Cayuga, and Gallagher Generating Stations. The Draft SIP presents IDEM’s reasonable progress analysis for each of the facilities and also provides an assessment of visibility in the Class I areas projected to be affected by the Duke Energy facilities. For the Gallagher Generating Station, the issue is moot because Duke Energy formally retired the facility in June 2021, and IDEM has revoked the Title V Operating Permit.

#### **Gibson**

For Gibson, the Draft SIP first notes that the five EGUs are equipped with wet limestone fluidized-gas desulfurization (“FGD”) for SO<sub>2</sub> emissions with control efficiencies above 93% and selective catalytic reduction (“SCR”) for NO<sub>x</sub> emissions with control efficiencies above 81%.<sup>19</sup> It is important to note that the units are subject to the Mercury and Air Toxics Rule Subpart UUUUU, which requires that the installed emission controls be operated at all times coal is burned and which uses SO<sub>2</sub> reductions as a surrogate for acid gases. The Draft SIP should reflect this.

The Draft SIP should also note these controls represent state-of-the-art controls that cannot reasonably be improved upon. Further, given the nature of the controls at Gibson, the Draft SIP could reasonably conclude that any additional changes to the controls at the facility could not be expected to achieve significant emission reductions or have meaningful visibility impacts. The Draft SIP could also cite EPA’s 2019 Guidance to support a determination that no additional controls are warranted for consideration because the Gibson units are well-controlled, as the 2019 Guidance describes.<sup>20</sup>

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<sup>18</sup> Appendix U at 1.

<sup>19</sup> Draft SIP at 57.

<sup>20</sup> 2019 Guidance at 22-25 (Explaining that it is not necessary to evaluate additional controls for “[s]ources that already have effective emission control technology in place”).

Relying on Duke Energy's 2019 Integrated Resource Plan ("IRP"), the Draft SIP also explains that one of the Gibson units is expected to retire before 2028.<sup>21</sup> Taking that retirement into account, the Draft SIP notes modeling that projects Gibson's NOx emissions will decrease "by 35% or almost 4,600 tons" from 2016 to 2028, and that the facility's SO<sub>2</sub> emissions will decrease "by 13% or nearly 2,000 tons."<sup>22</sup> The Draft SIP should explain that it is entirely appropriate for the state to consider expected retirements when projecting future emissions and visibility conditions.

In addition to the Gibson unit shutdown, lower projected NOx emissions from Units 2, 3, and 5 "are a direct result of CSAPR [the Cross-State Air Pollution Rule] and the change to Indiana's NOx Ozone Season budget in the Revised CSAPR Update Rule, which allots a much lower budget by 2028."<sup>23</sup> The Draft SIP should state that it relies in part on the emission reductions that will be achieved under the Revised CSAPR Update Rule to achieve reasonable progress. That is consistent with past EPA policy as to predecessor interstate transport rules, including CSAPR, prior to its most recent update. It is also especially appropriate with respect to Indiana and Gibson, in particular, because the Revised CSAPR Update will drive substantial emission reductions in the state and from Gibson.

The Draft SIP's discussion of visibility modeling results also explains that Gibson was identified as a source whose emissions potentially affected visibility in Cohutta Wilderness Area in Georgia, and Caney Creek and Upper Buffalo National Wilderness Areas, and Hercules-Glades and Mingo National Wilderness Areas in Arkansas and Missouri.<sup>24</sup> As to Cohutta, the Draft SIP explains that Georgia did not request any additional analysis of emissions from Gibson.<sup>25</sup> The area is also substantially below the adjusted glidepath for 2028.<sup>26</sup> With respect to Hercules-Glades and Mingo, the Draft SIP notes that Gibson contributes less than one percent of total visibility impacts at those Class I areas, and both of these areas are also well below the glidepath to natural visibility conditions.<sup>27</sup>

It would be appropriate for the Draft SIP to explain that the marginal effect on visibility that could be achieved by additional controls at Gibson would be insufficient to justify additional costs at the facility. Indeed, the substantial visibility improvement that has already been achieved, along with the projected improvements to come, are more than sufficient to achieve reasonable progress for the second planning period. It would also be appropriate for the Draft SIP to include these conclusions in the four-factor analysis section of the Draft SIP for Gibson, with a cross-reference to the appropriate section of the Draft SIP's visibility chapter.

## **Cayuga**

The Draft SIP notes that Cayuga Units 1 and 2 are controlled with FGD scrubbers "to reduce the station's sulfur dioxide emissions by approximately 95%" and low NOx burners ("LNB") and

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<sup>21</sup> Draft SIP at 55, Table 8-5.

<sup>22</sup> *Id.*

<sup>23</sup> *Id.* at 59.

<sup>24</sup> *Id.* at 211, 214.

<sup>25</sup> *Id.* at 211.

<sup>26</sup> *Id.* at 211, Graph 23-11.

<sup>27</sup> *Id.* at 215.

SCR to control NOx emissions.<sup>28</sup> These controls are state-of-the-art and the Draft SIP should explain that, given the controls already in place, any additional control requirements could not possibly be implemented in a cost-effective manner, nor could any marginal emission reductions be large enough to have any meaningful effect on visibility. Indeed, the Draft SIP should also make clear that no state requested emission reductions from these Cayuga units and no state or regional planning association identified Cayuga emissions for evaluation pursuant to the regional haze program. Considering all of these factors, the state has many additional reasons to reject reasonable progress controls for Cayuga during the second planning period.

The Draft SIP also explains that Cayuga Units 1 and 2 “are expected to retire according to Duke’s 2019 IRP resulting in 1108 MW of coal-fired retired power generation by 2028.” It goes on to assess the significant emission reductions that will result from the closure of these units by the end of the planning period. It is entirely appropriate for the Draft SIP to consider and evaluate these emission reductions when projecting future conditions. It may be appropriate for the Draft SIP to further explain that these unit retirements are not necessary to make reasonable progress for the second planning period, that any reductions that would result from such unit shutdowns would be in excess of reductions needed for reasonable progress, and that a reasoned assessment of the four factors must include a realistic approach for estimating future visibility conditions and emission inventories. As noted in the Draft SIP, IDEM has stated that it will further evaluate and address EGU sources as part of its January 31, 2025 progress report, and that statement should be reiterated here in the context of the expected retirement of Cayuga Units 1 and 2.

Finally, the Draft SIP notes that Cayuga Unit 4 is a turbine that fires natural gas and no. 2 fuel oil. It also notes that base year and 2028 total NOx emissions from Unit 4 are projected to be less than 1 ton per year. It would be helpful for the Draft SIP to explain IDEM’s reasons for not further evaluating Unit 4 for controls. In particular the Draft SIP could note the de minimis NOx emissions and exceptionally small impact, if any, the unit is likely to have on visibility.

### **Gallagher**

The Gallagher Generating Station ceased operation of all permitted emissions sources on May 3, 2021, and IDEM issued a revocation of the Title V Operating Permit for the facility on June 1, 2021. Therefore, the Draft SIP no longer needs to include evaluation of potential controls for the Gallagher units. Instead, the Draft SIP should describe the reductions in NOx and SO<sub>2</sub> emissions that will result from these unit shutdowns. Although those emission reductions should be viewed as in excess of what would otherwise be required for reasonable progress during the second planning period, the Draft SIP should recognize that the reductions are permanent, that they have occurred early in the second planning period, and that the shutdowns were not the result of any federal regulatory requirement. Accordingly, the Gallagher unit shutdowns and their associated emission reductions should be credited to Duke Energy. In that regard, the Draft SIP should explain that due to these additional emission reductions, it is particularly appropriate that no additional controls be required at Duke Energy’s remaining Indiana EGUs.

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<sup>28</sup> *Id.* at 69.



The comments above suggest that IDEM include findings and conclusions for the Duke Energy Gibson and Cayuga facilities evaluated in the Draft SIP related to the sufficiency of the existing controls at the sources, the cost-ineffectiveness of requiring additional controls at this time, and the minimal effects additional emission reductions from these sources would have on visibility and revise the analysis to show that the Gallagher facility has ceased operation. Duke Energy notes that the Draft SIP's explanation of IDEM's reasoning in chapter 26 reasonably addresses these points for all Indiana sources. Including additional discussion of these matters specific to each Duke Energy facility, however, would allow the state to present more granular, technical information supporting its decisions for these facilities and greater detail on the state's specific rationales for Gibson and Cayuga. Although this information should not strictly be necessary, it would likely resolve questions that commenters may raise about the state's conclusions for the Duke Energy facilities and should help support approval of the SIP.

#### **IV. Additional Comments by the FLMs Misinterpret the Draft SIP and Indiana's Proper Exercise of its Authority under the CAA and the RHR.**

The comments of the FLMs raise several additional issues that address overarching analytical or policy choices contained in the Draft SIP or that directly affect Duke Energy's Gibson Generating Station. IDEM's responses to those comments are entirely appropriate and effectively address the FLM's statements. Duke Energy provides further responses to these FLM comments here.

The FLMs state that any unit shutdowns IDEM relies on should be made enforceable.<sup>29</sup> NPS also states, specific to Gibson, that the retirement of Unit 4 at that facility should be made federally enforceable because the unit retirement was included in 2028 modeling projections.<sup>30</sup> The Forest Service states more broadly that "[f]uture operational status of emission units, operating scenarios for emission units that represent a reduced capacity, and pollution control equipment efficiency used to designate a unit as 'effectively controlled' need to be made federally enforceable."<sup>31</sup> Most importantly, IDEM explains in response to these comments that the projected unit shutdowns described in the Draft SIP are "are not included as a requirement in Indiana's long-term strategy for the second implementation period."<sup>32</sup> Accordingly, the state has determined that, with respect to these units and related EGUs that are not currently projected to shut down, existing controls and existing emission rate limits are adequate to achieve reasonable progress during the second planning period. Any additional emission reductions that might occur as a result of a unit shutdown during the second planning period would be in excess of what is needed for reasonable progress and could properly be evaluated as part of reasonable progress for the third planning period.

Moreover, the Forest Service's broader comments as to the enforceability of operating scenarios and control efficiencies and any other restrictions of emissions or effective emission restrictions do not appear to identify specific issues at any particular facility. To the extent the Forest Service

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<sup>29</sup> Appendix U at 3.

<sup>30</sup> *Id.* at 4.

<sup>31</sup> *Id.* at 12.

<sup>32</sup> *Id.* at 3.

believes modeling that projects different utilization rates in future years requires that those utilization rates be made enforceable, again, IDEM is not relying on those utilization rates to achieve reasonable progress for the second planning period.

In addition, as noted above in section II, EPA's 2019 Guidance recommends that states consider various factors when deciding whether to bring sources and source categories forward for a four-factor analysis. That includes consideration of the five additional required factors listed in 40 CFR 51.308(f)(2)(iv). Two of those factors are relevant here: (1) emission reductions due to ongoing air pollution control programs, and (2) source retirement and replacement schedules.<sup>33</sup> Reductions that will occur based on existing programs, like the Revised CSAPR Update Rule, are specifically included in the Draft SIP, are enforceable, and are appropriate considerations for not imposing additional control requirements on EGUs at this time.<sup>34</sup> The source-retirement factor allows for precisely the sort of considerations the state has included in its Draft SIP without imposing a requirement that the shutdowns taken into account in modeling be federally enforceable. Indeed, such a requirement would render this factor entirely impracticable to evaluate and essentially a dead letter.

It is also important to note that the federally enforceable requirement for consideration of unit shutdowns is based in EPA statements with respect to the consideration of remaining useful life as part of an assessment of the cost factor in a four-factor analysis.<sup>35</sup> They should have no bearing on consideration of the five additional factors. Moreover, to the extent EPA guidance on this issue attempts to dictate the manner in which states must balance the four reasonable progress factors (e.g., remaining useful life can only be considered as a lesser part of the cost factor) or to limit the weight states may give to any one factor (e.g., states can only give weight the remaining useful life if it is an enforceable requirement), EPA is likely running afoul of the law.<sup>36</sup>

NPS also comments that the increase of NO<sub>x</sub> emissions at Gibson Unit 1 appears anomalous compared to decreases at Units 2, 3, and 5.<sup>37</sup> The state's response is fully responsive. The Unit 1 increase is due to unusually low emissions in the 2016 base year, and emissions reductions due to the Revised CSAPR Update account for the additional emission reductions at the other units.

Finally, NPS comments criticize Indiana's decision to use a percent contribution analysis as part of its approach to preparing the Draft SIP. NPS first appears to suggest that Indiana should not evaluate sources based on their current percent contribution to visibility impairment but should

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<sup>33</sup> 2019 Guidance at 21-22.

<sup>34</sup> EPA's 2021 Guidance document instructs that states should not rely on these factors "to reject controls that are otherwise reasonable based on the four statutory factors" or "to summarily assert that the state has already made sufficient progress and, therefore, no sources need to be selected or no new controls are needed regardless of the outcome of four-factor analyses." 2021 Guidance at 13. Of course, that is not the case here. The state has brought sources forward for four-factor analysis and it has not exclusively or summarily based a decision not to require controls for EGUs based on these factors alone. The Draft SIP and these comments provide many valid reasons for why additional controls imposed under the regional haze program for the Duke Energy facilities are objectively unreasonable. The state is well within its rights to conclude that the Duke Energy facilities do not warrant additional controls based on the record developed.

<sup>35</sup> See, e.g., 2021 Guidance at 10.

<sup>36</sup> See *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1 (D.C. Cir. 2002).

<sup>37</sup> Appendix U at 4.

instead evaluate source contributions to impairment in excess of natural visibility conditions.<sup>38</sup> IDEM responds that “[i]t is more appropriate to show that reasonable progress has been made by 2028 towards reaching the 2064 visibility goal.”<sup>39</sup> What is clear is that there is nothing unreasonable about the approach Indiana has taken. The percent contribution of various sources to current visibility impairment and visibility impairment projected for 2028 provides valuable information from which the state can draw appropriate conclusions about the need for current-control requirements. There is nothing superior or more informative about the approach advocated by NPS and no reason for Indiana to reverse course on the basis of these conclusory comments.

NPS also suggests that Indiana has used an unsuitably low threshold for its percent contribution analysis, arguing that, in developing CSAPR, EPA used a one percent threshold.<sup>40</sup> The reason for this criticism is unclear. In Indiana’s analysis, “Class I areas which had a visibility impact of 1.5% or greater by emissions from Indiana sources were selected as areas that were significantly impacted,” based on 2011 emissions, which is a very conservative approach.<sup>41</sup> NPS has not provided any reason to adopt a different threshold, apart from the fact that EPA used a one percent threshold for the national ambient air quality standard (“NAAQS”) for ozone to determine upwind significant contribution to downwind nonattainment for purposes of developing CSAPR. NAAQS, with their strict, near-term statutory compliance deadlines, do not provide a suitable framework for addressing regional haze with its distant and entirely aspirational goal of achieving natural visibility conditions. Indeed, even EPA’s 2064 program end date is aspirational, not a requirement.

Regardless of the percent contribution analysis used by IDEM, it is clear that the Duke Energy facilities at issue in this proceeding received a thorough review and were subject to an analysis that makes clear that no additional controls are warranted for those EGUs in the second planning period. The Duke Energy EGUs do not contribute to perceptible or regulatorily meaningful visibility impairment. The relevant Class I areas are well below the glidepath to natural visibility conditions and are continuing to achieve significant emission reductions beyond any measure of what could realistically be called for under a reasonable progress standard.

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<sup>38</sup> *Id.* at 10.

<sup>39</sup> *Id.*

<sup>40</sup> *Id.*

<sup>41</sup> Draft SIP at 196.

**Boling, Jean**

---

**From:** Swercheck, Adam N (Allentown) USA <adam.swercheck@lehighhanson.com>  
**Sent:** Friday, November 12, 2021 3:34 PM  
**To:** Boling, Jean  
**Subject:** Lehigh Comments on Indiana Regional Haze SIP  
**Attachments:** 2021-11-12 Lehigh Cement Comments on IN Regional Haze SIP.pdf

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Ms. Boling,

Lehigh is submitting the attached comments related to the Indiana regional haze SIP publication that is currently open for public comment.

Thank you,  
Adam

**Adam N. Swercheck**  
Environmental Director

Lehigh Hanson, Inc.  
7660 Imperial Way  
Allentown, Pennsylvania 18195

Direct: (610) 295-1906  
Cell: (484) 426-7733  
[adam.swercheck@lehighhanson.com](mailto:adam.swercheck@lehighhanson.com)  
[www.lehighhanson.com](http://www.lehighhanson.com)





Lehigh Cement Company LLC

Corporate Office  
7660 Imperial Way  
Allentown, PA 18195-1040

November 3, 2021

Ms. Jean Boling  
Indiana Dept of Environmental Management  
Office of Air Quality, Room 1003  
100 North Senate Avenue  
Indianapolis, IN 46204

Re: Draft Indiana Regional Haze SIP for the Second Implementation Period  
Lehigh Cement Company Comments

Ms. Boling,

Lehigh Cement Company (Lehigh) has reviewed Indiana's draft regional haze state implementation plan (SIP) for the second implementation period. As you know, Lehigh currently operates cement kilns in the State of Indiana. Specifically, the existing long dry kilns in Mitchell, IN and the new modern preheater/precalciner kiln currently being constructed to replace them were part of the focus of this SIP development effort. Lehigh appreciates the opportunity to comment on the draft SIP and includes the enclosed comments for your consideration.

If you have any questions on the enclosed comments, please feel free to contact me at (484) 426-7733 or [adam.swercheck@lehighhanson.com](mailto:adam.swercheck@lehighhanson.com).

Sincerely,

*Adam N. Swercheck*

Adam N. Swercheck  
Environmental Director

Enc.

Cc: T. O'Neill  
W. Krause  
T. Crowther  
S. Quaas  
G. Ronczka

## Lehigh Cement Company Comments on Indiana Draft Regional Haze State Implementation Plan

Citation	Citation Text	Comment
Draft SIP, Section 11.1.2, Pg 113	The DSI systems are used minimally and were installed for the purposes of reducing HCl emissions at times.	Lehigh suggests removing the phrase “used minimally” because that is not the case. The existing DSI systems are used as necessary for the purposes of complying with the HCl-related requirements found in the NESHAP Subpart LLL regulations.
Draft SIP, Section 11.1.3, Pg 115 & Appendix G, Section 4.1.3, Pg 23	NOx or SO2 emission are not regulated under the NESHAPs for Hazardous Waste Combustors, 40 CFR 63, Subpart EEE.	Lehigh wants to clarify that the Mitchell kilns, and the future Mitchell kiln, will be regulated under NEHSAP for Portland Cement kilns, specifically 40 CFR 63, Subpart LLL.
Appendix G, Section 3.0, Pg 3	The final component of the pyroprocessing system is the clinker cooler. The clinker cooler serves three main purposes. • recoups up to 30% of the heat input to the kiln system. ...	Lehigh suggests the removal of the cited heat input because the thermal recovery is variable. Noting a specific heat input implies levels that are consistent and constant, which is not always the case in a cement kiln.
Appendix G, Section 3.1, Table 3-1, Pg 5	IDEM identifies various control performance characteristics with citation to resources, including the following:  Mid-Kiln Firing: 10-55% reduction in NOx SNCR: 45% reduction in NOx SCR: 90% reduction in NOx	The citations used to support performance characteristics for the identified technologies are dated, are not applicable to all cement kiln types, and may not be technically feasible. Specifically, the upper end of range associated with mid-kiln firing is unrealistically high for any modern kiln. The reference cited for SNCR shows a 30% maximum performance and is a document from 2008, yet 45% is stated in Appendix G. Furthermore, SNCR is capable of NOx reductions greater than 45% in some kiln designs. SCR has shown to be technically infeasible for numerous lime and cement kilns and should not be identified at all, and certainly not with an estimated NOx reduction attributed to it.
Appendix G, Section 3.1.1, Pg 7	Mid-kiln firing on its own can reduce NOx from 11 to 55 percent depending on fuel used and kiln design (EC/R Incorporated, 2009).	Lehigh does not believe there is any real data to support a mid-kiln firing control efficiency of up to 55% control in a long dry kiln, and asks that this statement be removed to avoid implying such efficiency is possible.

Citation	Citation Text	Comment
Appendix G, Section 3.1.2, Pg 8	SCR NOx reduction observed ranges from 70 to 90 percent.	<p>SCR is not a viable control technology for a cement kiln. Lehigh is only aware of two SCR applications on a cement kiln, which are Holcim Midlothian, which has a baghouse (PM) and wet scrubber (SO<sub>2</sub>) prior to the SCR unit, and Holcim Joppa, which has dry absorbent addition followed by an ESP prior to the SCR and a baghouse downstream of the SCR. These control schemes are unique and not representative of a cost-effective retrofit. In addition, only one of these systems may have been installed for NOx control. The other was for control of other pollutants.</p> <p>Sections 3.1.2 and 3.2.1 describe technological issues with SCR technology when applied for cement kiln NOx control, but do not state the technology is technically infeasible but rather provide cost estimates for the technology in Table 3-2. Lehigh believes such information is misleading and any cost information must account for the entire process and equipment configuration needed to support operation of a SCR system even if it was technically feasible.</p>
Appendix G, Section 3.2.1, Table 3-2, Pg 10	<p>IDEM presents various cost ranges for NOx controls regardless of feasibility and cites very low, lower-end range cost effectiveness and a single value for cost of SNCR as follows:</p> <p>LNB + Indirect: \$200-\$21,100/ton  Mid-Kiln Firing: \$600-\$3,600/ton  SNCR: \$1,400/ton  SCR: \$600-\$17,700/ton</p>	<p>Lehigh does not believe IDEM should present cost ranges for all control technologies independent of any information on kiln type, installation, how cost was derived, etc. Doing so is misleading. Also, where a control technology is not feasible, such as SCR, installation should not be costed and would have to consider requirements for upstream/downstream controls and reheat of flue gas for optimal catalytic reaction, as necessary. Lehigh does not believe such considerations were included in the stated cost estimates. Control cost cited should have a breakdown akin to Appendix C. Region 8 Cement Kiln BART Analyses and Appendix D. Greencastle BART Control Analyses which are specific to the facility and variables associated with that installation.</p>

Citation	Citation Text	Comment
Appendix G, Section 3.3, Table 3-3, Pg 13	<p>IDEM has cited performance criteria for Advanced Flue Gas Desulfurization (AFGD) of 95-99.5% reduction in SO<sub>2</sub>. A 2005 LADCO analysis is cited. This is reiterated in Section 3.3.1 under AFGD.</p> <p>IDEM states in Section 3.3.1 for AFGD: AFGD has not been used in cement kilns before.</p> <p>AFGD is not generally considered technically feasible for cement kilns.</p>	<p>In general, AFGD is not considered technically feasible for cement kilns. Furthermore, it is unlikely the 99.5% reduction is supportable via the literature for a cement kiln and would, almost certainly, not be offered as a performance guarantee by a control technology vendor, especially if the technology has not been employed by any cement plant. Lastly, while IDEM states the technology is not technically feasible, Lehigh objects to IDEM providing control efficiency estimates as though it is technically feasible.</p>
Appendix G, Section 3.4.1, Table 3-4, Pg 17	<p>Similar to Table 3-2 for NO<sub>x</sub> controls, IDEM has presented cost ranges for SO<sub>2</sub> control technologies. Ranges are as follows:</p> <p>FGD – DSI: \$2,400-\$9,000/ton  FGD – Spray Dryer: \$2,300-\$88,800/ton  AFGD: \$2,400-\$47,100/ton  Wet FGD: \$1,500-\$78,800/ton</p>	<p>Lehigh does not believe IDEM should present cost ranges for all control technologies independent of any information on kiln type, installation, how cost was derived, etc. Doing so is misleading. Also, where a control technology is not feasible, such as AFGD, no cost information should be included as though it is feasible. Control cost cited should have a breakdown akin to Appendix C. Region 8 Cement Kiln BART Analyses and Appendix D. Greencastle BART Control Analyses which are specific to the facility and variables associated with that installation.</p>



**Boling, Jean**

---

**From:** SHAW, THOMAS <thomas.shaw@alcoa.com>  
**Sent:** Wednesday, November 03, 2021 9:22 AM  
**To:** Boling, Jean  
**Subject:** Alcoa comment on the Indiana Regional Haze State Implementation Plan for the Second Implementation Period  
**Attachments:** Burns & McDonnell Response to FLM Comments on Alcoa Warrick Four-factor Analysis 08-13-2021 highlighted yellow.pdf

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Good morning Jean,

Alcoa appreciates the opportunity to provide a comment on the Indiana Regional Haze State Implementation Plan for the Second Implementation Period. Alcoa's comment specifically addresses Section 17.2.6 Alcoa Reasonable Level of Control for SO<sub>2</sub> Emissions specifically, the second paragraph. In this paragraph It is noted that Warrick Newco LLC submitted additional information related to Alcoa's cost estimate and cost effectiveness analysis. Alcoa would like to correct the cost stated in the paragraph. The total correct costs associated with the Flue Gas Desulfurization for the potline is \$16,800 per ton and the Anode Baking Ring Furnace is \$45,500 per ton as noted on page 2 Below the SO<sub>2</sub> Controls Table (yellow highlight) of the August 13, 2021 report from Burns & McDonnell.

If you have any questions regarding the corrections, please do not hesitate to contact me.

Best regards,

Tom

Thomas Shaw, Ph.D.  
Manager Environmental  
Alcoa Warrick Operations  
4400 West State Road 66  
Newburgh, IN 47630  
Thomas.shaw@alcoa.com  
812-660-2602



Act with Integrity  
Operate with Excellence  
Care for People



August 13, 2021

Thomas Shaw, PhD.  
Environmental Manager  
Alcoa Warrick Operations  
[thomas.shaw@alcoa.com](mailto:thomas.shaw@alcoa.com)

**Re: Response to Federal Land Manager Comments on Alcoa Warrick Four-Factor Analysis**

Dear Tom,

As tasked by Alcoa Warrick Operations, Burns & McDonnell is pleased to provide the responses to two of Federal Land Manager Comments on Alcoa Warrick Four-Factor Analysis prepared by Burns & McDonnell, dated September 25, 2020.

1. *The inflation adjustment used in the Alcoa analysis is too high. The EPA CCM recommends use of the CEPCI which increased by 13% since the original 2007 cost estimates. Instead, Burns & McDonnell assumed a 2.5% annual interest rate which inflated costs by 38%.*

The capital and annual O&M cost estimates for a new FGD system on the potlines and the Anode Baking Ring Furnace that were summarized by IDEM in Table 1 has been updated per the Chemical Engineering Plant Cost Index (CEPCI) cost increase over the escalation period. The updated Table 1 rough order-of-magnitude costs for both Capital and Annual O&M costs are as follows:

Table 1. FGD System Cost Estimate Summary

Scrubber	Capital	Annual O&M
Potline 2 through 6	\$422,100,000	\$4,500,000
Anode Baking Ring Furnace	\$52,600,000	\$600,000
<b>Total</b>	<b>\$474,700,000</b>	<b>\$5,100,000</b>

2. *The Alcoa 4FA assumed 70% control efficiency for the FGD. This seems low. What is the basis for this assumption? Note, a 95% control efficiency was assumed for the FGD in the BART analysis for the Warrick facility in the previous round of RH planning.*

The Burns & McDonnell analysis did not use or present an FGD control efficiency as a specific efficiency was not required for FGD capital or Annual O&M cost estimating. However, EPA Guidance on retrofit SO<sub>2</sub> Emission Control Performance Assumptions does support an over 90% control efficiency for FGD technologies, and the "SO<sub>2</sub> Controls Table"



August 13, 2021

Page 2

from IDEM's Appendix J for the Alcoa aluminum plant has been updated to reflect a 95% control efficiency along with the revised costs Table 1 above:

**SO<sub>2</sub> Controls**

<b>Control Cost Summary</b>	<b>Potlines 2-6</b>	<b>Anode Baking Ring Furnace &amp; A-446 Dry Alumina Scrubbers</b>
	<b>Flue Gas Desulfurization</b>	<b>Flue Gas Desulfurization</b>
Total Capital Cost	\$422,100,000	\$52,600,000
Total Annual Cost (Capital & Operating)	\$4,500,000	\$600,000
Current Emissions (ton/yr)	3,000	139
Control Efficiency	95%	95%
New Emission Rate (tons/yr)	150	7.0
Emission Reductions (tons/yr)	2,850	132
Cost-Effectiveness (\$/ton)	\$1,579*	\$4,544*

\*Total Annual Cost as presented does not include indirect costs such as Capital Recovery.

Including Capital Recovery over 15 years at 6% interest, the corresponding Cost-Effectiveness would change to \$16,800 / ton for Potlines 2-6, and \$45,500 / ton for the Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers.

Note that the "SO<sub>2</sub> Controls Table" presents the "Annual O&M" costs prepared by Burns & McDonnell as "Total Annual Costs". Capital Recovery costs were not included in the Table 1 "FGD System Cost Estimate Summary" under the "Annual O&M" amounts, as the "Annual O&M" amounts were not intended to represent "Total Annual Cost".

Sincerely,

Ben Zhang, PhD, PE  
Industrial Services Manager  
847-275-8082 | bzhang@burnsmcd.com



August 13, 2021  
Page 3

Cc. Bill Celenza, PE, Sr. Process Engineer

## Appendix Y

### **EPA**

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**Boling, Jean**

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**From:** Blakley, Pamela <blakley.pamela@epa.gov>  
**Sent:** Monday, November 15, 2021 4:33 PM  
**To:** Boling, Jean  
**Cc:** Liu, Alisa  
**Subject:** EPA Region 5's Comments on proposed Indiana Regional Haze State Implementation Plan Revision for the 2nd Implementation Period  
**Attachments:** 2021-11-15 EPA R5 Public Comments on 9-29-2021 Indiana RH SIP - Final.pdf

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Good afternoon, Jean Boling,

Attached, please find EPA Region 5's comments on the proposed Indiana Regional Haze State Implementation Plan (SIP) Revision for the 2nd Implementation Period that was posted for public comment. Please note that our comments on Indiana's proposed SIP are for the purpose of SIP strengthening. For those comments where we emphasize the need for additional justification and information, it is important to have a clear understanding of how decisions are reached to help minimize opportunities for potential adverse comments in the future. If you have any questions, please feel free to contact me, or Alisa Liu at [liu.alisa@epa.gov](mailto:liu.alisa@epa.gov).

Sincerely,

Pamela Blakley, Supervisor  
Control Strategies Section  
Air and Radiation Division  
United States Environmental Protection Agency-Region 5

## ATTACHMENT

### US EPA Comments regarding the September 29, 2021 Draft for Public Comment of Indiana's Regional Haze State Implementation Plan

On September 29, 2021, Indiana Department of Environmental Management (IDEM) shared a link with USEPA Region 5 to Indiana's draft Regional Haze SIP that was posted for a public comment. The public comment period concludes on November 15, 2021. USEPA provides these comments geared toward additional information and justification to help further address the Regional Haze Rule requirements.

#### **General Comments**

In addition to the comments below, please refer to Region 5's responses dated March 5, 2021 to questions and comments from Federal Land Managers during the January 12, 2021 LADCO Regional Haze Meeting. These cover considerations for interest rates, retrofit factors, equipment lifespan, and visibility. They provide general comments to be considered as they apply within the context of Indiana's draft Regional Haze SIP and four-factor analyses.

For clarification of certain aspects of the Regional Haze Rule, please also refer to the July 8, 2021 memo from Peter Tsirigotis, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period" (July 8, 2021 Clarification Memo).

<https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation>

### **3.0 REGIONAL PLANNING FOR REGIONAL HAZE**

#### **Section 3.3 Federal Land Managers Consultation**

**Page 11:** IDEM provided the FLMs an opportunity for review of the draft RH SIP on May 18, 2021, at least 60 days prior to holding the public hearing for the SIP in accordance with 40 CFR 51.308(i)(2). . . . Comments received from the FLMs on the draft RH SIP were summarized and responses have been included in the final version of the RH SIP, Appendix U.

#### **Comment:**

The State should also include the summarized FLM comments and responses in the SIP narrative rather than just an appendix in accordance with 40 CFR 51.308(i)(3).

### **7.0 SOURCE SELECTION PROCESS**



## **Section 7.4 Reasonable Progress and Four-Factor Analyses**

**Page 44-45:** IDEM explains that the EGU sector was evaluated in detail during the first implementation period of the Regional Haze Rule. IDEM provides information on reductions of NO<sub>x</sub> and SO<sub>2</sub> in the tens of thousands from Indiana sources that have occurred over the past decade as reliance on coal over the past decade has declined and numerous EGUs have shut down or switched fuels. As such, IDEM did not include four-factor analyses for its EGUs in the draft Regional Haze SIP. Instead, IDEM provided information on emission trends, photochemical modeling to predict 2028 emissions, and source apportionment modeling to assess visibility impacts. IDEM plans to review the EGU sector for the January 31, 2025 progress report and evaluate the EGUs in more depth for the third implementation period.

### **Comment:**

As a general matter, EPA expects states to select their largest in-state contributors to visibility impairment for four-factor analysis. *See* July 8, 2021 Clarification Memo at 4. In Indiana's case, many of these largest contributors appear to be EGUs that have been screened in through the Q/d analysis. In some instances, IDEM may find it appropriate to not select such a source, even if it is one of the largest sources in the state. For instance, IDEM may decline to not select a particular source based on a demonstration that the source is operating existing effective controls. *See* August 2019 Guidance 22 – 25; July 8, 2021 Clarification Memo 5.

IDEM suggests that recent emission reductions owing to other control measures are a basis for not conducting a four-factor analysis. However, it is generally inappropriate to not select a source simply because it was part of an emissions sector that is the subject of numerous industrywide EGU control programs and downward emissions trends for the 1<sup>st</sup> planning period. As a general matter, once a source is screened in based on visibility impacts, a state should not forgo four-factor analysis merely because of other emission reductions (at the source or other sources) or because of recent improvements in visibility. As EPA stated in the July 8, 2021 Clarification Memo 13, “a state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas.” While in some instances, IDEM may determine that a source has existing effective controls such that a four-factor analysis is futile and unlikely to yield further cost-effective controls, that demonstration should be made on a *source-specific basis* and account for recent historical emission rate data for the source. *See* July 8, 2021 Clarification Memo 5.

More specifically, it is generally inappropriate to not select a source simply because it was the subject of BART controls in the first planning period. Moreover, IDEM relied on CAIR/CSAPR as a better-than-BART alternative for

the EGUs. In this case, it is even less clear that such a source can forgo four-factor analysis on the basis of existing effective controls. As the Regional Haze Rule states, "After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraphs (d) and (f) of this section [relating to reasonable progress], as applicable, in the *same manner* as other sources." 40 CFR 51.308(e) (emphasis added). Additionally, the 2019 Regional Haze Guidance notes that it "may be reasonable for a state not to select a particular source for further analysis" for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period...(Footnote 54)." However, footnote 54 states, "This consideration ... is not applicable to...BART-subject units for which the BART requirement was met in whole or in part by emission reductions at other units as part of a better-than-BART alternative or trading program...and sources for which existing controls were determined to be BART. A state might, however, have a different, reasonable basis for not selecting such sources for control measure analysis." 2019 Regional Haze Guidance at 25.

IDEM further indicates that it plans to evaluate EGUs in the forthcoming mid-term progress report. We agree that such an evaluation can shed important light on EGUs and commend IDEM on its intent to conduct further analysis; however, the progress report is not a substitute for conducting the four-factor analysis in the comprehensive SIP revision. Indeed, the four-factor analysis and progress report requirements of the regulation are in separate regulatory provisions. Compare 40 CFR 51.308(f)(2)(1) with 40 CFR 51.308(g). Indiana must comply with both requirements and cannot rely on one to substitute for the other.

Finally, IDEM states that it has completed a "reasonable progress analysis," even though that analysis does not appear to be a four-factor analysis in accordance with 40 CFR 51.308(f)(2)(i). IDEM's "reasonable progress analysis" is more of an emissions trends analysis. EPA has explained that reasonable progress cannot be determined prior to or independently from the analysis of control measures for sources. See 82 FR 3078, 3091/3 (Jan. 10, 2017); Clarifications Memo at 6. IDEM must therefore determine what is necessary to make reasonable progress in the second implementation period by using the four factors to analyze control measures for sources. While progress made in the first implementation period, ongoing emission trends, and anticipated changes in emissions (including due to shutdowns, on-the-way controls, or other factors) may inform a state's regional haze planning process, these circumstances alone do not satisfy a state's obligation to determine and include in its SIP the measures that are necessary to make reasonable progress.

In general, EPA recommends that Indiana conduct a four-factor analysis for each of its largest in-state sources of visibility impairment, including EGUs, or

alternatively demonstrate that a particular source has existing effective controls such that a four-factor analysis would be futile.

## **8.0 REASONABLE PROGRESS ANALYSIS FOR INDIANA'S ELECTRIC GENERATING UNITS SELECTED SOURCES**

### **Comment:**

IDEM suggests that recent emission reductions owing to other control measures are a basis for not conducting a four-factor analysis for the selected EGUs. However, it is generally inappropriate to not select a source simply because it was part of an emissions sector that is the subject of numerous industry-wide EGU control programs and downward emissions trends for the 1<sup>st</sup> planning period. As a general matter, once a source is screened in based on visibility impacts, a state should not forgo four-factor analysis merely because of other emission reductions (at the source or other sources) or because of recent improvements in visibility.

Therefore, IDEM should explain in greater detail how not selecting EGUs for a four-factor analysis still ensures reasonable progress towards natural visibility. If the various control measures and shutdowns listed in this section are necessary for reasonable progress and therefore part of IDEM's Long-Term Strategy, those must be federally enforceable and in the SIP. See more detailed comments on this issue under Section 7.4.

### **Section 8.3 Planned Retirements and Shutdowns for Coal Fired EGUs at Indiana Power Plants**

**Page 55-56:** Table 8-5 lists Indiana EGUs and Expected Unit Retirements by 2028.

### **Comment:**

Please indicate which, if any, of the retirements are federally enforceable and planned for inclusion in the long-term strategy (LTS) and SIP. Please describe the regulatory mechanisms IDEM uses to ensure retirements and shutdowns are federally enforceable and permanent.

**Page 56-57:** IDEM cites to planned retirements at various utilities announced in the Integrated Resource Plans (IRP) that are projected to occur during the third implementation period of the Regional Haze Rule. Based on these projections, IDEM explains that requiring new emission controls at this time would not be cost effective since reductions in visibility impairment from Indiana EGUs is already occurring.

### **Comment:**

For these planned retirements, if IDEM chose to perform four-factor analyses on EGUs, IDEM could fully support its assertion that new emission control equipment is not cost-effective, if that is ultimately the case. A cost-effectiveness analysis within a four-factor analysis would provide actual data to support (or

refute) this claim. If the State is relying on anticipated source shutdowns as part of its long-term strategy for making reasonable progress, IDEM must make these planned retirements enforceable in the SIP. This includes reliance on shutdowns both to forgo a four-factor analysis and to shorten the remaining useful life of a source in conducting a four-factor analysis. See EPA Clarifications Memo at 10; see also Guidance at 20 and 34. If IDEM does not include these retirements in its SIP, then the State should consider a four-factor analysis for these sources.

Without the four-factor analyses, the reference to “cost-effective method” on page 57 of the draft noted above offers no support for the argument that “additional emissions reductions through the use of new emission control equipment or emissions limitations is not desired”. Further, decreasing emissions trends do not free the state from an obligation to meet the CAA and Regional Haze Rule requirements to consider what is necessary for reasonable progress, which may in fact be “new emission control equipment or emissions limitations.”

## **11.0 FOUR-FACTOR ANALYSES FOR INDIANA’S CEMENT KILNS**

### **Section 11.4 Greencastle Plant Four-Factor Analysis for Chosen NO<sub>x</sub> and SO<sub>2</sub> BART**

**Page 122:** IDEM provided updated information on the cost effectiveness of SNCR at Lone Star Industries, Inc. dba Buzzi Unicem USA - Greencastle Plant of \$1679 per ton NO<sub>x</sub>. On page 225, IDEM states generally that none of the controls identified through the four-factor analysis would be cost effective given the small amount of emission reductions that would be achieved.

**Comment:**

IDEM should specifically address whether the cost-effectiveness of the \$1679/ton control option for SNCR is reasonable and make a specific finding as to the Greencastle facility regarding whether new controls will be required for reasonable progress.

## **13.0 FOUR-FACTOR ANALYSES FOR INDIANA’S IRON AND STEEL MILL PLANTS**

**Comment:**

There are various instances throughout the four-factor analyses where IDEM concludes that X (one of the sources) has “no reasonable set of NO<sub>x</sub> emission control measures beyond what is currently installed and operated for these emission units” or “[X] already utilizes [Y] as an existing NO<sub>x</sub> emission control measure.” However, IDEM should take its analysis one step further and indicate whether those conclusions mean that they are determining that existing measures are necessary for reasonable progress. As a general matter, EPA believes that existing measures are necessary for reasonable progress and therefore must be incorporated into the regulatory portion of the SIP. However, the state may make

a weight-of-evidence demonstration that a particular existing measure is not necessary for reasonable progress. See July 8, 2021 Clarification Memo 8-10.

#### **13.9.6 Cleveland-Cliffs Burns Harbor Reasonable Level of Control for SO<sub>2</sub> Emissions**

**Page 157:** IDEM cites to the cost effectiveness of \$4000/ton SO<sub>2</sub> for Coke Oven Gas Desulfurization for the Clean Coke Oven Gas Export Line and Flare emission unit. On page 225, IDEM states generally that none of the controls identified through the four-factor analysis would be cost effective given the small amount of emission reductions that would be achieved.

**Comment:**

As with the other four-factor analyses, IDEM does not appear to make specific findings for each facility of whether the cost effectiveness of the controls evaluated is reasonable. Somewhere in the SIP document, such as Section 26.0 Decision on What Control Measures are Necessary to Make Reasonable Progress, IDEM should make specific findings for each facility regarding whether the cost effectiveness for a new control option within a certain range is reasonable and if it will be required for reasonable progress. As to the cost effectiveness of controls for the Burns Harbor emission units of \$4,000/ton SO<sub>2</sub>, IDEM would be expected to address the reasonableness of options in this range.

### **15.0 PLASTICS MANUFACTURING PLANT**

#### **15.2.6 and 15.3 SABIC Innovative Plastics, Reasonable Level of Control for NO<sub>x</sub> and SO<sub>2</sub>**

**Pages 172-177:** IDEM provides Graph 13-1 showing decreases in NO<sub>x</sub> emissions after ending the use of coal for process operations at the SABIC facility.

**Comment:**

Is there an enforceable prohibition on coal burning at the source or is it now physically impossible to use coal as a fuel source in the future?

#### **17.2.6 Alcoa Reasonable Level of Control for SO<sub>2</sub> Emissions**

**Page 182:** IDEM provided revised cost-effectiveness estimates for FGD retrofits of \$1579/ton SO<sub>2</sub> for Potlines 2-6 and \$4544/ton SO<sub>2</sub> for the Anode Baking Ring Furnace and A-446 Dry Alumina Scrubbers unit.

**Comment:**

IDEM should specifically address cost-effectiveness estimates in this range and make a specific finding for the facility regarding whether these costs are reasonable and if they will be required for reasonable progress.

## **26.0 DECISION ON WHAT CONTROL MEASURES ARE NECESSARY TO MAKE REASONABLE PROGRESS**

**Page 223-228:** IDEM provided a weight-of-evidence demonstration consisting of information from IDEM's reasonable progress analysis and four-factor analyses to support the state's decision not to require additional control measures for the sources selected for evaluation.

### **Comment:**

If IDEM determines that no additional (i.e., new) measures are necessary to make reasonable progress for a particular source, the State must then determine whether the source's existing measures are necessary to make reasonable progress. See section 4 (pages 8 – 12) of the Clarifications Memo for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If IDEM concludes that the existing controls at a selected source are necessary to make reasonable progress, IDEM must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP).

Beyond the decision regarding whether to require additional control measures, a description of the weight-of-evidence demonstration needed is outlined in the July 8, 2021 Clarification Memo for determining when existing control measures are necessary to make reasonable progress. The weight-of-evidence demonstration consists of much of what IDEM has already provided; however, IDEM would need to place it into the context of the four statutory factors.

The 2019 Regional Haze Guidance describes how to demonstrate sources are already effectively controlled such that "a full four-factor analysis would likely result in the conclusion that no further controls are necessary." 2019 Regional Haze Guidance at 23. Several examples of existing effective controls are provided in the 2019 Regional Haze Guidance on pages 22-25. In providing support for any conclusion that sources are already effectively controlled, we recommend that for each selected source the State considers whether the source can achieve or is already achieving a lower emission rate using its existing measures. If a source is capable of operating or is already operating at a lower emission rate than assumed either (1) as the basis for not conducting a full four-factor analysis or (2) as the baseline for four-factor analysis, that lower rate should be analyzed as a potential control measure. Similarly, we recommend IDEM consider whether equipment upgrades might be reasonable. If either more efficient use of existing measures or equipment upgrades are potentially reasonable control options, we recommend the State either conduct a four-factor analysis or explain why it is reasonable to forgo doing so. See Clarifications Memo at 5, 7.

If IDEM asserts that existing control measures are not necessary to make reasonable progress, the weight-of-evidence demonstration is explained in the July 8, 2021 Clarification Memo: “Specifically, if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emission increases.” July 8, 2021 Clarification Memo at 9.

For the weight-of-evidence demonstration, IDEM would need to provide information on the historical and projected emission rates not just mass emissions as follows:

- (1) the source’s past implementation of its existing measures and its historical emission rate, (2) the source’s projected emissions and emission rate, and (3) any enforceable emissions limits or other requirements related to the source’s existing measures. July 8, 2021 Clarification Memo at 9.

To the extent data for mass emission and emission rates will be used to demonstrate a source’s past performance using its existing measures to help inform the expected future operation of that source, “data from the most recent 5 years (if available) is sufficient to make this showing”. July 8, 2019 Clarification Memo at 9.

#### **Section 26.1 Impact of Sulfur Dioxide and Nitrogen Oxides Emissions Reductions on Reasonable Progress Goals**

**Comment:**

Section 26.1 contains IDEM’s conclusions regarding the State’s decision not to require additional control measures. This is the heart of IDEM’s main finding, although it doesn’t appear until page 225. Therefore, it would be helpful if IDEM would provide conclusions specific to the selected sources indicating what, if any, additional control measures are determined to be necessary for reasonable progress. If no additional control measures are selected by Indiana, IDEM should further explain (1) if that determination means that existing measures are necessary for reasonable progress, and (2) how a determination of no additional control measures nonetheless ensures reasonable progress is made.

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## Appendix Y

**IEA**

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**Boling, Jean**

---

**From:** Mindy Westrick Brown <mwestrick@indianaenergy.org>  
**Sent:** Friday, November 12, 2021 11:02 AM  
**To:** Boling, Jean  
**Cc:** Mindy Westrick Brown  
**Subject:** IEA Comments - Regional Haze SIP Proposal  
**Attachments:** IEA Comments Regional Haze SIP Proposal Final.pdf

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---

Dear Jean,

The IEA appreciates the opportunity to provide the attached comments on IDEM's Regional Haze SIP Proposal.

Please do not hesitate to contact me should have questions or need additional information.

Thank you,  
Mindy

Mindy Westrick Brown  
Vice President  
Indiana Energy Association  
One American Square  
Suite 1600  
Indianapolis, IN 46282  
Office: (317) 632-4406  
Cell: (260) 645-0222  
Email: [mwestrick@indianaenergy.org](mailto:mwestrick@indianaenergy.org)





Danielle M. McGrath, President

Mindy Westrick Brown, Vice President

November 12, 2021

- ▶ AES Indiana
- ▶ Boonville Natural Gas Corp.
- ▶ CenterPoint Energy
- ▶ Citizens Energy Group
- ▶ Community Natural Gas Co., Inc.
- ▶ Duke Energy Indiana
- ▶ Fountaintown Gas Co., Inc.
- ▶ Indiana Michigan Power
- ▶ Indiana Natural Gas Corp.
- ▶ Midwest Natural Gas Corp.
- ▶ Northern Indiana Public Service Co.
- ▶ Ohio Valley Gas Corp.
- ▶ South Eastern Indiana Natural Gas Co., Inc.
- ▶ Sycamore Gas Co.

Via Email – jboling@idem.IN.gov

Ms. Jean Boling  
Indiana Department of Environmental Management  
Office of Air Quality, Room 1003  
100 North Senate Avenue  
Indianapolis, IN 46204

Dear Jean,

The IEA member companies appreciate the time IDEM has taken to develop its Regional Haze SIP Proposal. This thorough examination of the available information surrounding the NOx and SO2 emitting facilities in Indiana has resulted in a reasonable plan that supports continued economic growth in the state.

Further, we believe that IDEM has correctly determined that the remaining fossil fuel-fired Electric Generating Units (EGUs), with multiple recent retirements and additional add-on controls since the first planning period, continue to provide a source of meaningful emission reductions during this planning period. These meaningful reductions will likely continue into the next planning period as the remaining EGUs either have emission controls that are considered highly efficient for SO2 and NOx or will be shut down prior to 2028. Additionally, several additional units are targeted for shutdown no later than 2028.

I am available should you have any questions regarding our written comments.

Sincerely,

A handwritten signature in black ink, appearing to read "Mindy Westrick Brown".

Mindy Westrick Brown

✉ Info@IndianaEnergy.org

☎ 317.632.4406

🌐 IndianaEnergy.org

📍 One American Square  
Suite 1600  
Indianapolis, Indiana 46282

## Appendix Y

### **MAIN VU**

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**Boling, Jean**

---

**From:** Paul Miller <pmiller@nescaum.org>  
**Sent:** Friday, November 05, 2021 11:30 AM  
**To:** Boling, Jean  
**Subject:** Comments from MANE-VU on Draft Indiana Regional Haze SIP for the Second Implementation Period  
**Attachments:** MANE-VU\_Comments\_IDEM\_RH\_SIP\_20211105.pdf

\*\*\*\* This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. \*\*\*\*

---

Dear Ms. Boling:

Please find attached comments being submitted by the Mid-Atlantic/Northeast Visibility Union (MANE-VU) on the Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period.

Sincerely,

**Paul J. Miller**, Lead Manager  
Mid-Atlantic/Northeast Visibility Union (MANE-VU)  
89 South Street, Suite 602, Boston, MA 02111 | Ph: 617-259-2016  
[www.nescaum.org](http://www.nescaum.org)  
he/him/his

November 5, 2021

Connecticut

Delaware

District of Columbia

Maine

Maryland

Massachusetts

New Hampshire

New Jersey

New York

Pennsylvania

Penobscot Indian Nation

Rhode Island

St. Regis Mohawk Tribe

Vermont

Jean Boling

Indiana Department of Environmental Management

Office of Air Quality, Room 1003

100 North Senate Avenue

Indianapolis, IN 46204

VIA EMAIL: [jboling@idem.IN.gov](mailto:jboling@idem.IN.gov)

*RE: Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period*

Dear Ms. Boling:

The Mid-Atlantic/Northeast Visibility Union (MANE-VU) appreciates the opportunity to comment on the Indiana Department of Environmental Management's (IDEM's) draft Regional Haze State Implementation Plan (SIP) for the Second Implementation Period that was made available for review on September 28, 2021 (hereinafter, the "IDEM draft"). MANE-VU is the regional visibility planning organization of the air agencies in the Mid-Atlantic and Northeast. MANE-VU includes eleven states, two tribal nations, and the District of Columbia. It coordinates regional haze planning activities to help its members reduce visibility impairment at Class I areas in the MANE-VU region in furtherance of achieving the national visibility goals of EPA's Regional Haze Rule (RHR). To facilitate reasonable progress in visibility protection at its own Class I areas, and at all Class I areas throughout the U.S., MANE-VU is providing comments on the IDEM draft.

The IDEM draft is of interest to MANE-VU because MANE-VU identified Indiana emissions as significantly contributing to visibility impairment at Class I areas in the region. MANE-VU consulted with Indiana and other states identified as "contributing," and Indiana was included in the list of states receiving the MANE-VU Inter-RPO "Ask" for contributing states.<sup>1</sup> The Indiana response and resolution to this Ask must be described in its draft regional haze SIP for review and action by EPA and Federal Land Managers (FLMs) prior to approval. MANE-VU's comments below relate to meeting the MANE-VU

<sup>1</sup> *Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) States Concerning a Course of Action in Contributing States Located Upwind of MANE-VU Toward Assuring Reasonable Progress for the Second Regional Haze Implementation Period (2018-2028)*, August 25, 2017. Available at <https://otcair.org/MANEVU/Upload/Publication/Formal%20Actions/MANE-VU%20Inter-Regional%20Ask%20Final%208-25-2017.pdf>.

MANE-VU Class I Areas

Acadia National Park

Maine

Brigantine Wilderness

New Jersey

Great Gulf Wilderness

New Hampshire

Lye Brook Wilderness

Vermont

Moosehorn Wilderness

Maine

Presidential Range

Dry River Wilderness

New Hampshire

Roosevelt Campobello

International Park

Maine/New Brunswick,

Canada



Inter-RPO Ask. Comments on specific sections of IDEM's draft are provided following the Inter-RPO Ask discussion.

#### *MANE-VU Ask*

MANE-VU's technical analysis identified visibility-impairing emissions from Indiana and other upwind states as reasonably anticipated to contribute to visibility impairment at MANE-VU Class I areas. Based on this analysis, MANE-VU developed a "MANE-VU Ask" that was sent to Indiana and the other identified states with five requests for consideration during the upwind states' second regional haze SIP planning effort. With this letter, MANE-VU is providing our overarching perspective on how well IDEM's draft addresses each of these requests. MANE-VU makes note of the past and future EGU retirements and emissions reductions described in Sections 8.1.1 and 8.3 of IDEM's draft. Nevertheless, MANE-VU respectfully requests that its Ask items be addressed in IDEM's regional haze SIP as described in the comments that follow.

Ask #1: EGUs  $\geq$  25 MW with installed controls, ensure that controls are run year round.

IDEM's draft SIP does not address MANE-VU Ask #1. As described in Section 7.4 of the IDEM draft, IDEM has elected to defer analysis of its EGU sector until the third implementation period. While the workload distribution of source category analysis to different implementation periods is allowed under EPA guidance, IDEM's approach of deferring analysis of its EGU sector is inconsistent with MANE-VU's Inter-RPO Ask for the second implementation period. To this end, MANE-VU notes the Indiana EGU emissions reductions that occurred between 2009 and 2019 as described in Section 8 of IDEM's draft. Nevertheless, MANE-VU reiterates its request that IDEM pursue enforceable mechanisms to ensure that EGUs  $\geq$  25 MW with installed controls run those controls year round.

Ask #2: For emissions sources having a  $3.0 \text{ Mm}^{-1}$  impact or greater at MANE-VU Class I areas, perform a four-factor analysis.

The IDEM draft does not address MANE-VU Ask #2. The Indiana Michigan Power Company (dba American Electric Power) Rockport Plant (Facility ID 6166) was identified by MANE-VU technical analysis as a facility with the potential for  $3.0 \text{ Mm}^{-1}$  impact or greater at one or more of MANE-VU's Class I areas. MANE-VU notes the emissions controls and reductions for the Rockport Plant discussed in Section 8.5 of the IDEM draft, including the continuous operation of SCRs and enhanced DSI systems. Nevertheless, MANE-VU respectfully requests that a four-factor analysis be performed for the Rockport Plant, consistent with MANE-VU's Ask #2, to determine the reasonableness of more stringent control efficiencies or stricter emissions limits.

Ask #3: Adopt an ultra-low sulfur fuel oil standard.

The IDEM draft does not address the MANE-VU ultra-low sulfur fuel oil Ask. MANE-VU respectfully re-iterates its request that Indiana adopt ultra-low sulfur fuel oil standards as part of its long-term strategy, or demonstrate in its SIP why it would not be feasible to do so. For distillate oil, this would be essentially the equivalent of on-road diesel, which is already widely

available. We note that all MANE-VU states have successfully adopted low sulfur fuel oil requirements.

Ask #4: For EGUs and other large sources, pursue enforceable mechanisms to lock in lower emission rates.

MANE-VU notes the EGU emissions reductions described in Section 8 of the IDEM draft, including those that have come about via enforceable mechanisms, such as consent orders. However, IDEM does not directly address MANE-VU's Ask #4 in its draft SIP.

Ask #5: Encourage and promote energy efficiency and clean technologies.

The IDEM draft does not address Ask #5. MANE-VU respectfully asks that IDEM consider, and report in its SIP, measures or programs in Indiana that reduce emissions by encouraging energy efficiency and promoting cleaner energy technologies. Rather than a focus on energy markets, this would be a discussion within IDEM's haze SIP of the energy efficiency measures and clean energy programs under consideration or currently operating in Indiana. Unlike MANE-VU's other Ask items, MANE-VU does not necessarily intend that these measures be enforceable or included as part of a state's long-term strategy. But because such programs can reduce emissions and therefore benefit visibility, MANE-VU is asking its upwind state partners to consider and report such measures in their haze SIPs.

### *Section-Specific Comments*

#### **7.3 Q/d Screening Analysis for Source Selection**

MANE-VU respectfully asks IDEM to describe in its SIP the technical basis for selecting 5 as the Q/d screening threshold for screening sources.

#### **23.1 Class I Area Selection**

At the bottom of page 199, below Table 23-2, the text states, "Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions[.]" Although this statement is true for some of the Class I areas shown in Table 23-2, it does not appear to be true for many others.

#### **23.11 Brigantine Natural Wilderness Area, NJ; and Lye Brook National Wilderness Area, VT (MANE-VU)**

This section asserts that "on-the-books" measures, along with federal measures, are such that the meeting of reasonable progress goals (RPGs) will not be impeded. This section concludes that, as a result, no further analysis for this SIP will be taken. MANE-VU does not challenge the assertion that the meeting of RPGs will not be impeded, but re-iterates the fact that RPGs themselves are not enforceable and that the overarching goal of CAA 169A and the regional haze rule is to make progress towards the goal of natural visibility conditions by 2064. As emissions sources such as EGUs become better controlled, smaller additional emissions reductions from these sources, or emissions reductions from other source types, become necessary to make incremental improvements in visibility and to ensure that downward trends in monitored

visibility metrics continue. Therefore, MANE-VU further re-iterates its request that IDEM do additional work and analysis to ensure that MANE-VU's Inter-RPO Ask is addressed in its SIP such that incremental progress is made at MANE-VU Class I areas affected by Indiana emissions.

#### **25.0 20% CLEAREST DAYS ANALYSIS**

The first sentence in this section states, "Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions[.]" Although this statement is true for almost all of the Class I areas shown in Table 25-1, it does not appear to be true for Isle Royale, Brigantine, and Lye Brook.

Thank you for your efforts and your consideration of these comments. If you would like further clarification or discussion on any of these comments, please contact the MANE-VU Lead Manager Paul Miller ([pmiller@nescaum.org](mailto:pmiller@nescaum.org)) or the Chairs of the MANE-VU Technical Support Committee: Sharon Davis of the New Jersey Department of Environmental Protection ([sharon.davis@dep.nj.gov](mailto:sharon.davis@dep.nj.gov)) and David Healy of the New Hampshire Department of Environmental Services ([david.s.healy@des.nh.gov](mailto:david.s.healy@des.nh.gov)).

Sincerely,

Sharon Davis, New Jersey Department of Environmental Protection

David Healy, New Hampshire Department of Environmental Services

Co-Chairs, MANE-VU Technical Support Committee

cc: MANE-VU Directors

## Boling, Jean

---

**From:** Boling, Jean  
**Sent:** Monday, November 01, 2021 1:48 PM  
**To:** DELONEY, SCOTT; DERF, MARK; Bem, Susan  
**Subject:** FW: NJ Comments on IN Regional Haze SIP  
**Attachments:** IN - NJ Comment Letter\_11\_01\_2021 Final.pdf

**From:** Oluwaseun-Apo, Stella [DEP] <Stella.Oluwaseun-Apo@dep.nj.gov>  
**Sent:** Monday, November 01, 2021 10:15 AM  
**To:** Boling, Jean <JBoling@idem.IN.gov>  
**Cc:** Rand, Judy [DEP] <Judy.Rand@dep.nj.gov>; Davis, Sharon [DEP] <Sharon.Davis@dep.nj.gov>  
**Subject:** NJ Comments on IN Regional Haze SIP

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Good morning Ms. Boling,

Attached are New Jersey's comments on the draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period.

Thank you.

Stella Oluwaseun-Apo

Bureau of Air Quality Evaluation and Planning  
Tel: (609) 777-0430  
Fax: (609) 777-1343  
Email: [stella.oluwaseun-apo@dep.nj.gov](mailto:stella.oluwaseun-apo@dep.nj.gov)  
<http://www.nj.gov/dep/ages/index.html>



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State of New Jersey

DEPARTMENT OF ENVIRONMENTAL PROTECTION

DIVISION OF AIR QUALITY

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PHILIP D. MURPHY  
Governor

SHEILA Y. OLIVER  
Lt. Governor

SHAWN M. LATOURETTE  
Commissioner

FRANCIS C. STEITZ  
Director

November 1, 2021

*Submitted via email: jboling@idem.IN.gov*

Ms. Jean Boling  
Indiana Department of Environmental Management  
Office of Air Quality, Room 1003  
100 North Senate Avenue  
Indianapolis, IN 46204

Dear Ms. Boling:

Thank you for providing the New Jersey Department of Environmental Protection (NJDEP) the opportunity to comment on the draft Indiana Regional Haze State Implementation Plan revision titled, *Indiana Regional Haze State Implementation Plan for the Second Planning Period*, that was available for review on September 28, 2021. Indiana does not have any Class I areas; however, Indiana sources were determined to impact visibility in Class I areas in other States, including New Jersey.

Indiana was identified by New Jersey and the Mid-Atlantic/Northeast Visibility Union (MANE-VU) as significantly contributing to New Jersey's Class I area, the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge, and other Class I areas in MANE-VU. New Jersey and MANE-VU consulted with Indiana during the MANE-VU Regional Haze planning process for the second planning period. According to the federal Regional Haze rule (40 CFR § 51.308 (f)(2)(ii)(B)), "The States must consider the emission reduction measures identified by other States as being necessary to make reasonable progress in the mandatory Class I Federal area." New Jersey worked with MANE-VU to develop reasonable emission reduction strategies, or "Asks", necessary to make reasonable progress in Brigantine Wilderness Area and other impacted Class I areas. New Jersey's Asks include measures for Indiana to address as a contributing State to the Brigantine Wilderness Area.

New Jersey's specific comments are as follows:

**1. Emission Reduction Measures Identified in the New Jersey "Asks"**

Indiana did not address New Jersey's Asks in their proposed SIP as required by 40 CFR § 51.308(f)(2)(ii)(A), "The State must demonstrate that it has included in its implementation plan all measures agreed to during

state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement." New Jersey recognizes Indiana's past and future EGU retirements and emission reductions including those that have enforceable mechanisms, as described in Sections 8 of Indiana's draft Regional Haze SIP. However, Indiana's election to defer the analysis of its EGU sector until the third planning period of Regional Haze is inconsistent with New Jersey's EGU Asks for the second planning period, including year-round controls for EGUs  $\geq 25$  MW. In addition, Indiana does not directly address New Jersey's Asks in its SIP.

Indiana does not address New Jersey's ultra-low sulfur fuel oil Ask. New Jersey requests that Indiana adopt ultra-low sulfur oil standards consistent with New Jersey's Ask as part of its long-term strategy, or document in its SIP how it considered the four statutory factors in determining that the adoption of the strategy is not reasonable. It should be noted that all MANE-VU states have successfully adopted low sulfur fuel oil standards.

Energy efficiency measures include programs that reduce emissions that could benefit visibility, for example, cleaner energy technology and lowering demand for fossil fuel generation. Indiana should consider and document in its SIP any existing control strategies or programs that increase in-state use of Combined Heat and Power (CHP), and other clean Distribution technologies, and use energy efficiency to decrease energy demand to help improve visibility at Class I areas that it impacts.

Indiana should address and consider implementing the New Jersey Asks in its Regional Haze SIP to reduce emissions of sulfur dioxide and nitrogen oxides and improve visibility at Brigantine Wilderness Area.

## **2. Indiana Contribution to Visibility Impairment at New Jersey's Class I area**

New Jersey's analysis included varied methodologies and results for qualitative rankings. The results show that Indiana's contributions to visibility impairment at New Jersey and MANE-VU Class I areas were not marginal according to any of the analyses. As a matter of fact, Indiana ranked 5<sup>th</sup> in terms of maximum mass-weighted sulfate and nitrate contribution at any given MANE-VU Class I area, and 6<sup>th</sup> at Brigantine.<sup>1</sup> Therefore, the transport of haze precursors from Indiana to New Jersey's Class I area needs to be addressed in Indiana's SIP submittal for the second Regional Haze planning period.

Table 1: Maximum Extinction Contributions from Indiana Facilities at Brigantine Wilderness Area.

Rank	Facility Name	Unit ID	Max Extinction (Mm-1)
15	Rockport	MB1, MB2	3.835
33	Wabash River Generating Station	2,3,4,5,6	2.543
41	Tanner's Creek	U4	2.194

As shown in Table 1, the two units at the Rockport plant have the most impact on Brigantine Wilderness Area. New Jersey recognizes the emission controls and reductions for the Rockport Plant discussed in Section 8.5 of Indiana's draft SIP. However, New Jersey requests that a four-factor analysis be performed for the Rockport plant based on the MANE-VU Asks. New Jersey recognizes that units 2, 3, 4 and 5 in Wabash River Generating Station and unit U4 in Tanner's Creek were retired and shut down in 2015, and unit 6 in Wabash River was retired and shut down in 2016. New Jersey also recognizes that Indiana stated

<sup>1</sup> Please see Table 7 of the *Selection of States for MANE-VU Regional Consultation, September 5, 2017*. Available at (<https://otcair.org/manevu/document.asp?fview=Reports>).

in their SIP that these retirements and shutdowns were based on enforceable mechanisms such as consent decrees and new federal and state regulations.

### **3. Impact of Indiana's "No Further Analysis Needed" Decision at New Jersey's Class I area**

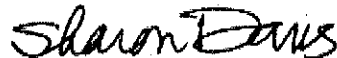
In Section 23 of Indiana's draft Regional Haze SIP, Indiana argues that LADCO's modeling shows that on-the-books measures and federal measures implemented during the first Regional Haze planning period, are sufficient to achieve reasonable progress at northeast Class I areas. Indiana stated that because of these measures, the 2028 reasonable progress goals in these areas will not be impeded and therefore decided that there will be no further analysis for its draft Regional Haze SIP. The northeast Class I areas meeting their RPGs does not exempt Indiana from considering additional controls that may be necessary to ensure incremental progress towards the federal Regional Haze rule and Clean Air Act goals of natural conditions by 2064. Indiana should implement the measures requested by New Jersey in the MANE-VU Inter-RPO Ask,<sup>2</sup> or equivalent measures, to reduce emissions from sulfur dioxide and nitrogen oxides and ensure incremental progress to improve visibility at Brigantine Wilderness Area.

Indiana does not consider New Jersey's identified measures as required by the Regional Haze rule at 40 CFR § 51.308 (f)(2)(ii)(B). Indiana must document how it addressed enforceable measures necessary for reasonable progress at Brigantine Wilderness Area presented in the MANE-VU Inter-RPO "Ask" in its final Regional Haze SIP submittal for review and action by EPA.

40 CFR § 51.308(f)(2)(ii)(C) states, "In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a Mandatory Class I Federal area, the State must describe the actions taken to resolve the disagreement." If Indiana decides not to implement New Jersey's Ask, then Indiana should include in its SIP the actions it plans to take to address its impacts on New Jersey's Class I area. New Jersey has determined that Indiana's implementation of the Asks is necessary to make reasonable and incremental progress at Brigantine Wilderness Area.

Thank you for the opportunity to comment on your proposed SIP. If you have any questions regarding this letter or wish to discuss further, please contact me at Sharon.Davis@dep.nj.gov.

Sincerely,



Sharon Davis, Chief  
Bureau of Evaluation and Planning

---

<sup>2</sup> *Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) States Concerning a Course of Action in Contributing States Located Upwind of MANE-VU Toward Assuring Reasonable Progress for the Second Regional Haze Implementation Period (2018-2028)*, August 25, 2017. Available at (<https://otcair.org/manevu/document.asp?fview=Formal%20Actions>)

c: (Email letter only)

Richard Ruvo, EPA Region 2

John Mooney, EPA Region 5

Francis C. Steitz, NJDEP

Kenneth Ratzman, NJDEP

Judy Rand, NJDEP

Stella Oluwaseun-Apo, NJDEP



## Appendix Y

### **Sierra Club**

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## Boling, Jean

---

**From:** Tony Mendoza <tony.mendoza@sierraclub.org>  
**Sent:** Wednesday, November 10, 2021 5:52 PM  
**To:** Boling, Jean  
**Cc:** Natalie Levine; DERF, MARK; kolson@citact.org; Jesse Kharbanda; Editor@protectnps.org; Wendy Bredhold; Stephanie Kodish; Emily Thompson; Josuha Smith; Colin Deverell  
**Subject:** Re: Regional Haze Comment Period Extension Request

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---

Hi, Jean, Mark -

We're going to submit comments on the haze SIP on Monday's deadline, and thank you again for the extension. I don't notice a time specified in the public notice. Are you willing to accept as timely comments submitted before midnight Eastern time on the 15th?

Thank you for your consideration.

Tony

On Mon, Oct 4, 2021 at 1:13 PM Boling, Jean <[JBoling@idem.in.gov](mailto:JBoling@idem.in.gov)> wrote:

Hello Natalie,

In response to the requests contained in your correspondence dated October 1, 2021, Indiana has extended the deadline for submitting comments on the *Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period* to November 15, 2021 and participants can join the public hearing scheduled for October 28, 2021 virtually via the following:

**Join Teams Meeting:**

<https://on.in.gov/oag>

**By Phone:**

317-552-1674

Conference ID: 414 222 415#

Best Regards,

*Jean Boling*

Senior Environmental Engineer  
Indiana Department of Environmental Management  
Office of Air Quality, Air Programs Branch  
100 North Senate Avenue, MC 61-53 IGCN 1003  
Indianapolis, IN 46204-2251  
Phone: 317-232-8228  
Fax: 317-233-5967  
E-mail: [jboling@idem.IN.gov](mailto:jboling@idem.IN.gov)

**From:** Natalie Levine <[nlevine@npca.org](mailto:nlevine@npca.org)>

**Sent:** Friday, October 01, 2021 3:35 PM

**To:** Boling, Jean <[JBoling@idem.IN.gov](mailto:JBoling@idem.IN.gov)>

**Cc:** DERF, MARK <[MDERF@idem.IN.gov](mailto:MDERF@idem.IN.gov)>; [kolson@citact.org](mailto:kolson@citact.org); Jesse Kharbanda <[JKharbanda@hecweb.org](mailto:JKharbanda@hecweb.org)>;  
[Editor@protectnps.org](mailto:Editor@protectnps.org); Wendy Bredhold <[wendy.bredhold@sierraclub.org](mailto:wendy.bredhold@sierraclub.org)>; Stephanie Kodish <[skodish@npca.org](mailto:skodish@npca.org)>;  
Emily Thompson <[Emily\\_Thompson@protectnps.org](mailto:Emily_Thompson@protectnps.org)>; Tony Mendoza <[tony.mendoza@sierraclub.org](mailto:tony.mendoza@sierraclub.org)>; Josuha Smith  
<[joshua.smith@sierraclub.org](mailto:joshua.smith@sierraclub.org)>; Colin Deverell <[cdeverell@npca.org](mailto:cdeverell@npca.org)>

**Subject:** Regional Haze Comment Period Extension Request

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Dear Ms. Boling,

On behalf of Citizens Action Coalition, Hoosier Environmental Council, Sierra Club, National Parks Conservation Association, and the Coalition to Protect America's National Parks, I am submitting to you a letter with a request to extend the public comment period and date of the public hearing for Indiana's Regional Haze State Implementation Plan for the Second Implementation Period.

We respectfully request a response by Friday, October 8<sup>th</sup>, so we can plan our comments most efficiently. Please don't hesitate to contact any of us with questions.

Best,

Natalie

## Boling, Jean

---

**From:** Colin Deverell <cdeverell@npca.org>  
**Sent:** Thursday, October 28, 2021 1:35 PM  
**To:** Boling, Jean  
**Subject:** Haze SIP NPCA Written Statement  
**Attachments:** Deverell Testimony\_IN Haze.pdf

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Hi Jean,

Attached is a written version of the comments I delivered at the hearing today on Indiana's proposed State Implementation Plan for Regional Haze on behalf of NPCA's members and supporters. Please let me know if you have any questions.

Thank you,  
-Colin



**Colin Deverell**  
*Midwest Senior Program Manager* | National Parks Conservation Association  
C: 312-720-0224 | [cdeverell@npca.org](mailto:cdeverell@npca.org) | [npca.org](http://npca.org)  
*Your parks. Your turn.*



## Comments on Indiana Regional Haze State Implementation Plan Colin Deverell, National Parks Conservation Association

Good afternoon, my name is Colin Deverell and I am the Midwest Senior Program Manager for the National Parks Conservation Association (NPCA). Thank you for the opportunity to comment today on Indiana's Regional Haze State Implementation Plan for the Second Implementation Period.

NPCA is a national, nonpartisan nonprofit organization with 1.6 million members and supporters across the country with over 20,000 in Indiana. Indiana has three national park sites and one of the country's newest national parks, Indiana Dunes National Park along Lake Michigan. Though Indiana does not have any Class I areas, air pollution from the state has a huge impact on air quality in local Indiana communities and other treasured nearby parks and Class I areas like Mammoth Cave National Park in Kentucky.

The Clean Air Act's Regional Haze Rule is an effective program that has resulted in real, measurable, and noticeable improvements in national park visibility and air quality. State Implementation Plans developed under the Regional Haze Rule are an opportunity—and obligation—for states including Indiana to reduce pollution from some of their biggest sources and other contributors to regional haze.

The State Implementation Plan (SIP) currently proposed for Indiana falls short of meeting the goals of the program and clearing the air in parks and our communities. If the state submits its plan as-is to the U.S. EPA, it will not comply with the Clean Air Act and the Regional Haze Rule as it does nothing new to limit haze-causing air pollution.

According to NPCA's analysis, coal plants in Indiana account for seventy-two percent of the total visibility impairing emissions in the state. These sources will release more than 40,000 tons of nitrous oxide (NOx) and 50,000 tons of silicon dioxide (SO<sub>2</sub>) in the next decade if further controls are not required. Remarkably, IDEM arbitrarily exempted these sources from a review of emission-reducing measures for this planning period. Furthermore, IDEM failed to evaluate all the technically feasible controls for non-coal plant sources such as steel mills and cement kiln facilities. These two actions combined leave the Indiana SIP woefully inadequate to make reasonable progress towards clean air in Class I areas and neighboring communities.

Additionally, the SIP fails to adequately address equity and environmental justice impacts, as encouraged by the EPA. The same sources of pollution causing haze in our national parks are also disproportionately affecting the health of communities near those sources; communities that are most often living below the poverty line and/or are communities of color. Northwest Indiana is home to six sources of concern, five of which are in Lake County which is comprised of 45% people of color and 17% of the community is below the poverty. Communities like Whiting and Gary, facing water and land pollution in addition to air, have borne these burdens for too long.

The health of these communities, and those across Indiana, is affected by the same pollutants that the Regional Haze program is designed to reduce. Air pollution drives up healthcare costs and makes it harder for kids to learn and play and adults to work. By requiring additional

emission-reducing measures and technically feasible controls, the Indiana SIP would have a powerful impact on improving community health.

To conclude my comments, NPCA requests that the state significantly revises its draft SIP to fulfill its obligations under the Clean Air Act. Specifically, we request you:

- Fully analyze reasonable progress emission controls for all coal plants in the state in this planning period. It is commonplace for coal plants to have scrubbers that reduce upwards of 98% of SO<sub>2</sub> emissions and selective catalytic reduction systems to reduce 95% of emissions of nitrogen oxides. Indiana cannot disregard these controls or upgrades to those facilities that already have them installed with weak performance;
- Evaluate all applicable controls for non-power plant sources and correct the cost of controls calculations;
- Thoroughly assess environmental justice impacts; and,
- Set enforceable retirements for any sources being counted on for pollution reduction.

Thank you for your time and I look forward to reviewing improvements to this plan.

## Boling, Jean

---

**From:** Rebecca Dien-Johns (rebecca.dien-johns@sierraclub.org) Sent You a Personal Message <kwautomail@phone2action.com>  
**Sent:** Thursday, October 28, 2021 11:44 AM  
**To:** Boling, Jean  
**Subject:** Draft Indiana Regional Haze State Implementation Plan for the Second Implementation Period

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Dear Jean Boling,

IDEM's draft plan for regional haze doesn't actually require polluters to reduce harmful air pollution and protect visibility at our national parks or Hoosiers' public health, and that is unacceptable. Your plan must require polluters to reduce sulfur dioxide and nitrogen oxides. These pollutants cause haze and also cause a wide range of public health harms. Please require polluters such as Duke's Gibson coal plant, AES's Petersburg coal plant, US Steel and Alcoa's Warrick aluminum smelter to reduce pollution and protect parks and public health.

Sincerely,

Rebecca Dien-Johns  
612 N Temple Ave  
Indianapolis, IN 46201  
rebecca.dien-johns@sierraclub.org  
(317) 702-3736

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club Hoosier Chapter. If you need more information, please contact Amanda Shepherd at Sierra Club Hoosier Chapter at amanda.shepherd@sierraclub.org or (317) 822-3750.



## Appendix Y

### **Sierra Club, Mendoza**

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Comment Type	PDF Page #(s)	Commenter, Last (or Co. name)	Commenter, First	Date	Time
PDF Index 217 - 218					
Sierra Club, Email #2	219	Mendoza	Tony	11/15/2021	8:15 PM
Sierra Club, Email #1	220	Mendoza	Tony	11/15/2021	8:12 PM
	221 thru 358	Exhibit 1	Regional Haze Four-Factor Analysis, USS		
	359 thru 442	Exhibit 2	GCC Rio Grande - Pueblo Cement Plant, Pueblo, Colorado, Four Factor Reasonable Progress Analysis, October 5, 2021		
	443 thru 547	Exhibit 3	Holcim - Florence Cement Plant, Florence, Colorado, Four Factor Reasonable Progress Analysis, September 30, 2021		
	541 thru 548	Exhibit 4	Worksheets		

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## Mitchell, Catherine

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**From:** Boling, Jean  
**Sent:** Wednesday, November 24, 2021 9:30 AM  
**To:** Mitchell, Catherine  
**Subject:** FW: Conservation Organizations' Comments on Indiana Regional Haze SIP (Email 3 of 3)  
**Attachments:** Exhibit 3 - Holcim Florence Plant\_Klafka Report.pdf

Add here's the second part.

Thank you, Ms. Catherine!

**From:** Tony Mendoza <tony.mendoza@sierraclub.org>

**Sent:** Monday, November 15, 2021 8:15 PM

**To:** Boling, Jean <JBoling@idem.IN.gov>; DERF, MARK <MDERF@idem.IN.gov>

**Cc:** Shore.Debra@epa.gov; Mooney, John <Mooney.John@epa.gov>; Joshua Smith <joshua.smith@sierraclub.org>; Stephanie Kodish <skodish@npca.org>; Sara Laumann <sara@laumannlegal.com>; Editor@protectnps.org; Ashley Williams <ashley.williams@sierraclub.org>; Jesse Kharbanda <JKharbanda@hecweb.org>; jp55biod@att.net; victoria@savedunes.org

**Subject:** Conservation Organizations' Comments on Indiana Regional Haze SIP (Email 3 of 3)

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---

Ms. Boling -

Attached please find Exhibit 3 to our comments. Please let me know if you have difficulty accessing this document.

Tony

---  
Tony Mendoza (*he, him, his*)

Senior Attorney

Sierra Club Environmental Law Program

2101 Webster St., 13th Floor

Oakland, CA 94612

(415) 977-5589

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## Mitchell, Catherine

---

**From:** Boling, Jean  
**Sent:** Wednesday, November 24, 2021 9:30 AM  
**To:** Mitchell, Catherine  
**Subject:** FW: Conservation Organizations' Comments on Indiana Regional Haze SIP (Email 2 of 3)  
**Attachments:** Exhibit 1.pdf; Exhibit 4 - Steel Mills.xlsx; Exhibit 2 - GCC Rio Grande\_Pueblo Cement\_Klafka Report.pdf

Here's the first part.

**From:** Tony Mendoza <tony.mendoza@sierraclub.org>

**Sent:** Monday, November 15, 2021 8:12 PM

**To:** Boling, Jean <JBoling@idem.IN.gov>; DERF, MARK <MDERF@idem.IN.gov>

**Cc:** Shore.Debra@epa.gov; Mooney, John <Mooney.John@epa.gov>; Joshua Smith <joshua.smith@sierraclub.org>; Stephanie Kodish <skodish@npca.org>; Sara Laumann <sara@laumannlegal.com>; Editor@protectnps.org; Ashley Williams <ashley.williams@sierraclub.org>; Jesse Kharbanda <JKharbanda@hecweb.org>; victoria@savedunes.org; jp55biod@att.net

**Subject:** Conservation Organizations' Comments on Indiana Regional Haze SIP (Email 2 of 3)

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---

Ms. Boling -

Attached please find Exhibits 1, 2, and 4 to our comments. Please let me know if you have difficulty accessing those three documents.

Tony

Tony Mendoza (*he, him, his*)

Senior Attorney

Sierra Club Environmental Law Program

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## Exhibit 1

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# REGIONAL HAZE FOUR-FACTOR ANALYSIS

**U. S. Steel – Mon Valley Works  
Clairton Plant**



Submitted To:

**ALLEGHENY COUNTY HEALTH DEPARTMENT  
PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION**

Prepared By:

Ian Donaldson – Managing Consultant  
Christi Wilson – Principal Consultant  
Jeremy Jewell – Principal Consultant  
Kyle Dunn, PE – Managing Consultant

**TRINITY CONSULTANTS**

4500 Brooktree Road  
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Revised October 29, 2020



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## 1. EXECUTIVE SUMMARY

---

On June 8, 2020, U. S. Steel received a letter from the Allegheny County Health Department (ACHD) serving as a Regional Haze Four-Factor Analysis Information Collection Request (ICR). Per the ICR, ACHD requested that a four-factor analysis be performed for U. S. Steel's Clairton Plant (the Plant) located in Clairton, Pennsylvania based on the Plant's emissions profile and distance to Shenandoah National Park. The Plant produces coke and coke by-products through operation of ten coke batteries and additional support operations (e.g., boilers).

As shown in Sections 3 and 4, the possible emissions reduction options for sulfur dioxide (SO<sub>2</sub>) or nitrogen oxides (NO<sub>x</sub>) were found to either be technically infeasible or cost prohibitive (e.g., more than \$14,000 per ton of pollutant removed). Even if a control option had been found to be both technically and economically feasible, the emissions reductions would not result in a meaningful visibility improvement as demonstrated in Section 5.

## 2. FOUR-FACTOR ANALYSIS INTRODUCTION

---

Per the June 8, 2020 ICR, this four-factor analysis report provides information related to SO<sub>2</sub> and NO<sub>x</sub> emissions reduction options for the Clairton Plant. SO<sub>2</sub> and NO<sub>x</sub> emissions units at the Plant that were identified in the ICR include ten coke batteries (Batteries 1, 2, 3, 13, 14, 15, 19, 20, B, and C), six boilers (Boilers 1, 2, 5, 6, 7, and 8), and one SCOT incinerator. Emissions from the coke batteries are further broken out into three separate categories: combustion, pushing, and fugitives.

The Plant byproduct recovery system includes a unique cryogenic process that removes nitrogen-bearing organic compounds such as pyridine, and a desulfurization process that includes an “HCN Destruct” unit to remove HCN, from the coke oven gas (COG). The byproduct plant is designed to recover sulfur to yield a saleable product; therefore, the process is designed to achieve the highest feasible levels of sulfur removal from the COG. Furthermore, U. S. Steel completed upgrades to the desulfurization process in 2016 that involved installation and operation of a Vacuum Carbonate Unit (VCU). Carbonate feed gas (i.e., COG) from the byproduct plant is sent to the VCU. Within the VCU, COG passes through a soda ash solution in a trayed absorber column. Hydrogen sulfide (H<sub>2</sub>S) is then absorbed by the soda ash and the desulfurized gas exits the absorbed column as a desulfurized fuel which is in turn used by downstream U. S. Steel combustion sources in the Mon Valley. The VCU upgrade led to substantial decreases in the H<sub>2</sub>S content in downriver COG as identified by ACHD in Figure 3-1 of the Attainment Demonstration for the 2010 SO<sub>2</sub> NAAQS Nonattainment Area SIP.<sup>1</sup> These nitrogen- and sulfur-removing processes are considered baseline controls for all combustion sources at the Plant and will not be discussed further in this analysis.

U. S. Steel would also like to note that an air permit application was submitted for a cogeneration project for the Plant. This project would result in the removal of three boilers (Boiler 1, Boiler 2 and Boiler R-1) and a significant emissions reduction for the remaining boilers. The project planning and permitting are currently delayed due to the coronavirus pandemic. Should this project move forward, it would significantly impact the economic feasibility determinations prepared for this analysis.

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered, in accordance with instructions in the ICR:

- ▶ Technical feasibility
- ▶ Control effectiveness
- ▶ Emissions reductions
- ▶ Time necessary for implementation<sup>2</sup>
- ▶ Remaining useful life<sup>13</sup>
- ▶ Energy and non-air quality environmental impacts<sup>13</sup>
- ▶ Costs of implementation<sup>13</sup>

Section 3 of this report presents information for the SO<sub>2</sub> emissions reduction options, and Section 4 presents information for the NO<sub>x</sub> emissions reduction options. Referenced information is included in Appendix A.

---

<sup>1</sup> Attainment Demonstration for the Allegheny, PA SO<sub>2</sub> Nonattainment Area 2010 Standards, September 14, 2017. ([https://alleghenycounty.us/uploadedFiles/Allegheny\\_Home/Health\\_Department/Programs/Air\\_Quality/SIPs/SO2\\_2010\\_NAAQ\\_S\\_SIP\\_9-14-2017.pdf](https://alleghenycounty.us/uploadedFiles/Allegheny_Home/Health_Department/Programs/Air_Quality/SIPs/SO2_2010_NAAQ_S_SIP_9-14-2017.pdf))

<sup>2</sup> These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. See 40 CFR § 308(f)(2)(i).

### 3. SO<sub>2</sub> EMISSIONS REDUCTIONS OPTIONS

---

This report addresses the following SO<sub>2</sub> emissions reduction options:

- ▶ Wet Flue Gas Desulfurization (WFGD)<sup>3</sup>
- ▶ Dry Flue Gas Desulfurization (DFGD)<sup>15</sup>
- ▶ The PROven<sup>®</sup> system (coke ovens)

Based on a review of similar facilities and a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), there were no potential control technologies identified for the SCOT incinerator. The SCOT incinerator is the tail-end control of the SCOT plant, whose whole purpose is sulfur recovery/reduction. One entry for a SCOT (incinerator) was identified in the RBLC for a sour gas sweetening facility located in Wyoming, but no add-on controls were identified. The RBLC entry is included as Appendix B. U. S. Steel is already required to, and will continue to, maintain and operate the SCOT incinerator in accordance with good engineering and air pollution control practices. These practices, in combination with system design, allow for the Clairton Plant's system to achieve 99.8% efficiency from the SCOT plant and there are no means to increase this further.

#### 3.1 Technical Feasibility

Regarding combustion sources, DFGD and WFGD are considered technically feasible for the boilers, but not for the coke oven underfiring. The reason for infeasibility for the coke oven underfiring systems is based on the problems encountered with the use of flue gas emissions control technology on the coke oven batteries that employed them in the past. Furthermore, there are no known coke batteries currently using these technologies.<sup>4,5</sup>

For coke oven pushing emissions, an FGD system could potentially be installed following the PEC baghouse. However, this type of arrangement is not known to have been either applied, attempted, or even studied for a coke oven battery pushing emissions control system. The full scope of technical issues that may be associated with this type of arrangement is therefore unknown. As seen for other applications of air pollutant emissions control technologies, such as the employment of ESPs for coking cycle COG combustion emissions control, actual experience often reveals issues that are difficult to predict even when appreciable study has been done. Nevertheless, for the purpose of this analysis, a WFGD was considered technically feasible for this application as a conservative approach. A traveling hood attached to a fixed duct would also need to be installed to capture the pushing emissions and route them to the scrubber.

The PROven<sup>®</sup> system (Pressure Regulated Oven) regulates pressure within each oven chamber where the collector main operates under a negative pressure during coking in order to reduce fugitive emissions from the ovens during charging and coking as compared to typical battery operations. Among the benefits of the PROven<sup>®</sup> system is that it will be effective in minimizing oven-to-flue leakage, and this will directly result in

---

<sup>3</sup> Air Pollution Control Technology Fact Sheet, EPA-452/F-03-034 (<https://www3.epa.gov/ttn/catc/dir1/ffdg.pdf>)

<sup>4</sup> National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coke Ovens: Pushing, Quenching, and Battery Stacks - Background Information for Proposed Standards, Final Report. United States Environmental Protection Agency, Research Triangle Park, NC. EPA-453/R-01-006 (February 2001)

<sup>5</sup> RTI International. Evaluation of PM<sub>2.5</sub> Emissions and Controls at Two Michigan Steel Mills and a Coke Oven Battery. Prepared for United States Environmental Protection Agency, by RTI International, Research Triangle Park, NC (February 2006)

lower SO<sub>2</sub> stack emissions because it will minimize overall fuel sulfur content. The PROven<sup>®</sup> system is currently installed on Coke Battery C (it was part of its original design), but this system is considered technically infeasible for the other coke ovens because it would involve a complete overhaul and a change in the basic design and operation of the existing batteries.

## 3.2 Control Effectiveness

Table 3-1 summarizes the emissions reductions for the technically feasible SO<sub>2</sub> emissions reduction options. These rates were based on EPA's Air Pollution Control Technology Fact Sheet for FGD.

**Table 3-1. Control Effectiveness of SO<sub>2</sub> Emissions Reduction Options**

<b>SO<sub>2</sub> Reduction Option</b>	<b>Emissions Reduction (Wt. %)</b>
WFGD	90%
DFGD	90%

## 3.3 Emissions Reductions

The ICR specifies a baseline period of 2017 for non-electric generating units (EGUs). Table 3-2 presents these baseline emission rates, the estimated controlled emission rates, and emission reduction potentials for each of the technically feasible SO<sub>2</sub> emissions reduction options.

**Table 3-2. Baseline and Controlled Emission Rates and Emissions Reductions of SO<sub>2</sub> Emissions Reduction Options**

<b>Emissions Unit</b>	<b>SO<sub>2</sub> Reduction Option</b>	<b>Baseline Emission Rate (tpy)</b>	<b>Controlled Emission Rate (tpy)</b>	<b>Emissions Reduction (tpy)</b>
Battery 1 Pushing	WFGD	2.06	0.21	1.85
Battery 2 Pushing	WFGD	2.06	0.21	1.85
Battery 3 Pushing	WFGD	2.06	0.21	1.85
Battery 13 Pushing	WFGD	1.72	0.17	1.54
Battery 14 Pushing	WFGD	1.72	0.17	1.54
Battery 15 Pushing	WFGD	1.72	0.17	1.54
Battery 19 Pushing	WFGD	2.68	0.27	2.42
Battery 20 Pushing	WFGD	2.68	0.27	2.42
Battery B Pushing	WFGD	52.92	5.29	47.63
Battery C Pushing	WFGD	23.52	2.35	21.16
Boiler 1	WFGD	109.87	10.99	98.88
	DFGD		10.99	98.88
Boiler 2	WFGD	121.44	12.14	109.29
	DFGD		12.14	109.29
Boiler 5	WFGD	0.27	0.03	0.24
	DFGD		0.03	0.24
Boiler 6	WFGD	6.63	0.66	5.97
	DFGD		0.66	5.97
Boiler 7	WFGD	5.78	0.58	5.20
	DFGD		0.58	5.20

<b>Emissions Unit</b>	<b>SO2 Reduction Option</b>	<b>Baseline Emission Rate (tpy)</b>	<b>Controlled Emission Rate (tpy)</b>	<b>Emissions Reduction (tpy)</b>
Boiler 8	WFGD	5.70	0.57	5.13
	DFGD		0.57	5.13

### 3.4 Time Necessary for Implementation

Consistent with numerous previous regional haze determinations – related to both Best Available Retrofit Technology (BART) five-factor analyses and reasonable progress four-factor analyses – across the U.S., a minimum of five (5) years from the effective date of an approved determination would be needed for implementing either of the FGD SO<sub>2</sub> emissions reduction options. Based on evaluations completed for other industrial sites, the five-year implementation timeline breaks down roughly as follows.

- ▶ General design and equipment specification – 12 months
  - Includes but not limited to: engineering design and review of feasibility, including modification to existing equipment to allow for FGD option, a review of alternative engineering approaches, sending out requests for proposal, having BID meetings, and onboarding 3<sup>rd</sup> party engineering firm and contractors.
- ▶ Environmental permitting – 18 months (overlapping step 1 by 6 months and step 3 by 12 months)
  - Includes but not limited to: evaluation of air, water, and waste changes in emissions, permitting applicability to federal, state and local regulations for air, water, and waste, permit application development, permit application reviews with regulating authorities, public comment for permits, and agency time to respond to comments and issue final permits.
- ▶ Detailed design, procurement and fabrication – 24 months
  - Includes but not limited to: equipment requests for proposals, BID meetings, contractual reviews with vendors, placing equipment orders, develop detailed design drawings, off-site fabrication as needed.
- ▶ On-site construction, addressing existing spatial concerns to accommodate technology, commissioning, and compliance testing – 24 months
  - Includes but not limited to: safety review of on-site construction activities including effects on existing operations, staging area development, lift-procedures, scheduling equipment availability, mechanical, electrical, and PLC installations, training for operations and maintenance, commissioning of equipment off-site and on-site, as required, and final compliance testing.

This timeline applies to a single unit. If an FGD system were to be required on more than one or perhaps two of the units, then U. S. Steel doubts that five years would be enough time for ensuring compliance for all units.

Based on the five year implementation timeline and assuming an EPA review and approval period of one (1) year following the second planning period (2PP) SIP proposal deadline of July 31, 2021, the earliest effective date for any control requirements would be July 31, 2022. This 1 year period would also consist of Federal Land Manager review and public comment periods. Adding the time necessary for implementation to this date results in assumed implementation date of July 31, 2027.

### 3.5 Remaining Useful Life

U. S. Steel has no plans to shut down any of the ovens or the SCOT incinerator. Some of the boilers may be retired as part of a proposed cogen project, but for the purposes of this analysis, this potential shutdown is not being considered. Therefore, a 20-year remaining useful life (RUL) value is assumed for all sources



based on engineering estimates. This is consistent with the recently re-drafted Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (CCM) chapter on wet and dry scrubbers, which states: “we expect an equipment life of 20 to 30 years for wet FGD systems.”<sup>6</sup> The draft CCM uses 30 years in an example for an always-on and presumably base-loaded utility boiler, but controls on industrial equipment are not expected to perform and persist in a consistent manner as for utilities. EPA recognizes this fact for other technology; Section 4.5 of this report provides a quote from the CCM.

### 3.6 Energy and Non-air Quality Environmental Impacts

The pumping of sorbent slurry is the most energy intensive component in the operation of an FGD system. As such, WFGD systems have higher overall energy demands than DFGD systems. WFGD systems do not require as fine of a sorbent powder as DFGD systems, and this results in a smaller energy requirement for sorbent pulverization.

For DFGD systems, blowers are used to inject the dry sorbent into the flue gas, so large pumps are not required as in a WFGD system. However, dry sorbent injection does require the use of a downstream particulate control device. These devices contribute additional pressure drop to the system, which requires additional fan power.

Most FGD systems use calcium or sodium-based sorbents. A WFGD system typically uses limestone for the reaction and produces gypsum as a by-product. The limestone and gypsum material handling will increase PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions. Since Allegheny County is nonattainment for PM<sub>2.5</sub>, this could be a significant issue. WFGD systems also create additional emissions of carbon dioxide (CO<sub>2</sub>) a regulated greenhouse gas (GHG).

### 3.7 Costs

Table 3-3 summarizes the estimated costs, including total annualized costs<sup>7</sup> and cost effectiveness, based on the emission reduction values from Table 3-2 for the technically feasible SO<sub>2</sub> reduction options. The costs for the WFGD for the coke oven pushing emissions is based on vendor estimates as per the BACT analysis associated with the installation of Battery C. EPA’s Air Pollution Control Technology Fact Sheet provides ranges for capital and O&M costs, relative to heat input capacity. Costs for FGD for the boilers were conservatively estimated using the lower end of these ranges. The costs for each option are based on information presented in Appendix A.

**Table 3-3. Estimated Costs of SO<sub>2</sub> Emissions Reduction Options**

<b>Emissions Unit</b>	<b>SO<sub>2</sub> Reduction Option</b>	<b>Total Annual Costs (\$/year)</b>	<b>Cost Effectiveness (\$/ton)</b>
Battery 1 Pushing	WFGD	598,085	323,075
Battery 2 Pushing	WFGD	598,085	323,075
Battery 3 Pushing	WFGD	598,085	323,075

<sup>6</sup> Draft Section 5 *SO<sub>2</sub> and Acid Gas Controls*, Chapter 1 *Wet and Dry Scrubbers for Acid Gas Control*, July 2020 (EPA-HQ-OAR-2015-0341-0082.pdf) p. 1-29.

<sup>7</sup> The capital costs are annualized using capital recovery factors (CRFs) based on the RULs presented in Section 3.5 and an interest rate of eight (8) percent.

<b>Emissions Unit</b>	<b>SO2 Reduction Option</b>	<b>Total Annual Costs (\$/year)</b>	<b>Cost Effectiveness (\$/ton)</b>
Battery 13 Pushing	WFGD	586,949	379,992
Battery 14 Pushing	WFGD	586,949	379,992
Battery 15 Pushing	WFGD	586,949	379,992
Battery 19 Pushing	WFGD	741,442	307,012
Battery 20 Pushing	WFGD	741,442	307,012
Battery B Pushing	WFGD	2,307,009	48,434
Battery C Pushing	WFGD	1,376,069	65,017
Boiler 1	WFGD	3,918,309	39,626
	DFGD	4,748,808	48,025
Boiler 2	WFGD	2,479,877	22,690
	DFGD	3,005,496	27,499
Boiler 5	WFGD	1,180,648	4,821,752
	DFGD	1,430,891	5,843,739
Boiler 6	WFGD	1,180,648	197,896
	DFGD	1,430,891	239,841
Boiler 7	WFGD	804,284	154,619
	DFGD	974,755	187,391
Boiler 8	WFGD	804,284	156,797
	DFGD	974,755	190,031

## 4. NO<sub>x</sub> EMISSIONS REDUCTIONS OPTIONS

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This report addresses the following NO<sub>x</sub> emissions reduction options:

- ▶ Selective Catalytic Reduction (SCR)<sup>8</sup>
- ▶ Selected Non-Catalytic Reduction (SNCR)<sup>9</sup>
- ▶ Low-NO<sub>x</sub> Burners (LNB)
- ▶ Flue Gas Recirculation (FGR)
- ▶ The PROven<sup>®</sup> system (coke ovens)

Based on a review of similar facilities and a review of EPA's RBLC, there were no potential control technologies identified for the SCOT incinerator.

### 4.1 Technical Feasibility

SCR is technically feasible for the boilers, but it is not technically feasible for the coke ovens for the following reasons:

- ▶ The temperature of the exhaust gas exiting the heat exchanger section of the oven heating chamber will be approximately 450 °F, which at best is at the low end of the temperature range in which the SCR functions effectively. Theoretically it is possible to either bypass the regenerator section of the coke oven combustion system or to construct a reheat system to bring the exhaust gas temperature back to within the SCR temperature window. However, the recovery of heat from the exhaust gas is a fundamental component of the overall NO<sub>x</sub> emissions minimization design of the coke oven. An alteration of this to ensure that the exhaust gas stays in the SCR temperature window may result in an overall reduction in the efficiency of the generation of heat needed for the coking process, which in turn would result in the generation of more emissions, possibly more than would be reduced by the SCR. The same issues apply to an exhaust gas reheating system.
- ▶ The concentration of NO<sub>x</sub> in the exhaust gas undergoes significant step changes as the underfiring system reverses. The catalyst activation energy and ammonia feed-forward system would not be capable of handling significant and instantaneous changes in NO<sub>x</sub> concentration. The result would be periods in which the SCR would not reduce NO<sub>x</sub> emissions effectively (or at all) and corresponding increases in ammonia slip emissions.
- ▶ Although the byproduct plant is designed to maximize the recovery of sulfur from COG produced in the ovens, there will still be an appreciable amount of sulfur level in the clean COG. Not only will the SCR catalyst be fouled and degraded by sulfur compounds in the clean COG, but the primary issue for SCR is the generation of higher particulate emissions due to the formation of ammonium sulfate and bisulfate. Since SCR requires ammonia to eliminate NO<sub>x</sub>, the reaction of ammonia with the sulfur in the clean COG is unavoidable. In addition to the effect of increasing particulate emissions, ammonium bisulfate formation will lead to maintenance issues because it is a particularly corrosive and adherent substance.
- ▶ In contrast to the boilers, internal combustion engines, and combustion turbines for which SCR has reached relatively widespread application, the nature of the coke oven process does not lend itself well

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<sup>8</sup> Air Pollution Control Technology Fact Sheet, EPA-452/F-03-032 (<https://www3.epa.gov/ttn/catc/dir1/fscr.pdf>)

<sup>9</sup> Air Pollution Control Technology Fact Sheet, EPA-452/F-03-031 (<https://www3.epa.gov/ttn/catc/dir1/fsnscr.pdf>)

to the types of maintenance procedures and schedules that are used for those other types of sources when SCR is used.

SNCR is technically feasible for the boilers, but it is not technically feasible for the coke ovens. There are no known applications, even at a demonstration level, of the application of this technology to a coke oven combustion system, and there is no evidence indicating that this is or has ever been studied. SNCR requires both an exhaust temperature of at least 1,500 °F and enough residence time at that temperature to allow the injected ammonia to mix with the exhaust gas and allow the NO<sub>x</sub> reduction reactions to come to completion. As discussed above relative to the feasibility of SCR, it is theoretically possible to construct a reheat system to bring the exhaust gas temperature to within the SNCR temperature window, and provide sufficient residence time for the NO<sub>x</sub> reduction reactions, but doing so would result in an overall reduction in thermal efficiency and would likely result in the generation of more emissions than would be reduced by the SNCR. Furthermore, since the application of this technology has not been demonstrated, it is possible that there are other technical feasibility issues that render this technology unworkable for this application.

LNBS are not technically feasible for either the coke oven systems or the boilers. A staged combustion system similar to LNB technology is employed on Battery C (PROven<sup>®</sup> system), but installing a similar system on any of the existing ovens would require a complete overhaul due to the fundamental design differences between Battery C and the rest of the coke ovens. For the boilers, burner manufacturers have indicated that replacement burners would not achieve a reduction in NO<sub>x</sub>, based upon the actual emission rates that are currently being achieved, for Boilers 2, 5, 6, 7 and 8. Boiler 1 is currently operating at or below burner manufacturer’s indicated rates during ozone season.

FGR is not technically feasible for the coke oven system. This option has not been attempted, or based on information in open literature, even studied, for a coke oven battery underfiring system. FGR helps minimize NO<sub>x</sub> formation by reducing the primary combustion temperature and decreasing the concentration of oxygen in the combustion zone. Furthermore, FGR is not technically feasible due to the large volume of gas associated with the underfire system design coupled with the fuel heat input values that are required.

Due to the low excess air already being achieved for the boilers, FGR will not be feasible for these sources. Further suppression of excess air by these means would likely terminate the flame or pilot. Greater reduction in excess air would also lead to incomplete combustion, resulting in an increase in VOC, CO, and PM emissions and opacity.

## 4.2 Control Effectiveness

Table 4-1 summarizes the emission rates for the technically feasible NO<sub>x</sub> emissions reductions options for the boilers. These rates were taken from vendor estimates.

**Table 4-1. Control Effectiveness of NO<sub>x</sub> Emissions Reduction Options for the Boilers**

<b>NO<sub>x</sub> Reduction Option</b>	<b>Emissions Reduction (Wt. %)</b>
SCR	80%
SNCR	45%

### 4.3 Emissions Reductions

Table 4-2 presents the baseline emission rates and the controlled emission rates and emission reduction potentials for each of the technically feasible NO<sub>x</sub> emissions reduction options for the boilers.

**Table 4-2. Baseline and Controlled Emission Rates and Emissions Reductions of NO<sub>x</sub> Emissions Reduction Options for the Boilers**

<b>Emissions Unit</b>	<b>NOX Reduction Option</b>	<b>Baseline Emission Rate (tpy)</b>	<b>Controlled Emission Rate (tpy)</b>	<b>Emissions Reduction (tpy)</b>
Boiler 1	SCR	562.40	112.48	449.92
	SNCR		309.32	253.08
Boiler 2	SCR	188.93	37.79	151.14
	SNCR		103.91	85.02
Boiler 5	SCR	0.47	0.09	0.38
	SNCR		0.26	0.21
Boiler 6	SCR	13.85	2.77	11.08
	SNCR		7.61	6.23
Boiler 7	SCR	12.04	2.41	9.63
	SNCR		6.62	5.42
Boiler 8	SCR	10.03	2.01	8.03
	SNCR		5.52	4.52

### 4.4 Time Necessary for Implementation

A minimum of five (5) years from the effective date of an approved determination would be needed for implementing any of the NO<sub>x</sub> emissions reduction options. Based on evaluations completed for other industrial sites, the five-year implementation timeline breaks down roughly as follows.

- ▶ General design and equipment specification – 12 months
  - Includes but not limited to: engineering design and review of feasibility, including modification to existing equipment to allow for NO<sub>x</sub> control options, a review of alternative engineering approaches, sending out requests for proposal, having BID meetings, and onboarding 3<sup>rd</sup> party engineering firm and contractors.
- ▶ Environmental permitting – 18 months (overlapping step 1 by 6 months and step 3 by 12 months)
  - Includes but not limited to: evaluation of air, water, and waste changes in emissions, permitting applicability to federal, state and local regulations for air, water, and waste, permit application development, permit application reviews with regulating authorities, public comment for permits, and agency time to respond to comments and issue final permits.
- ▶ Detailed design, procurement and fabrication – 24 months
  - Includes but not limited to: equipment requests for proposals, BID meetings, contractual reviews with vendors, placing equipment orders, develop detailed design drawings, off-site fabrication as needed.
- ▶ On-site construction, addressing existing spatial concerns to accommodate technology, commissioning, and compliance testing – 24 months
  - Includes but not limited to: safety review of on-site construction activities including effects on existing operations, staging area development, lift-procedures, scheduling equipment availability,

mechanical, electrical, and PLC installations, training for operations and maintenance, commissioning of equipment off-site and on-site, as required, and final compliance testing.

This timeline applies to a single unit. If an SCR or SNCR system were to be required on more than one or perhaps two of the units, then U. S. Steel doubts that five years would be enough time for ensuring compliance for all units.

Based on the five year implementation timeline and assuming an EPA review and approval period of one (1) year following the 2PP SIP proposal deadline of July 31, 2021, the earliest effective date for any control requirements would be July 31, 2022. This 1 year period would also consist of Federal Land Manager review and public comment periods. Adding the time necessary for implementation to this date results in assumed implementation date of July 31, 2027.

## 4.5 Remaining Useful Life

U. S. Steel has no plans to shut down any of the ovens or the SCOT incinerator. Some of the boilers may be retired as part of a proposed cogeneration project, but for the purposes of this analysis, this potential shutdown is not being considered. Therefore, a 20-year RUL value is assumed for all sources based on engineering estimates. This is consistent with the recently updated OAQPS CCM chapter on SCR, which states: “the equipment lifetime of an SCR system is assumed to be 30 years for power plants and 20 to 25 years for industrial boilers”<sup>10</sup> and the example used in the recently updated chapter on SNCR.<sup>11</sup>

## 4.6 Energy and Non-air Quality Environmental Impacts

SNCR is a post-combustion NO<sub>x</sub> control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO<sub>x</sub>, forming nitrogen and water. The success of this process in reducing NO<sub>x</sub> emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700 °F to 2,000 °F. At temperatures greater than the upper end of this range, the reagent will be converted to NO<sub>x</sub>, and at temperatures less than the lower end of this range, the reagent will not react with the NO<sub>x</sub> and ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the boilers have an exhaust temperature of approximately 400 °F. Even strategically placing the ammonia injection further upstream would likely result only in peak temperatures of around 1,300 °F. Such a low temperature would require that additional fuel be combusted at some point to raise the temperature to the levels where SNCR will operate effectively. Combustion of the additional fuel would not only increase the NO<sub>x</sub> emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

A disadvantage of an SCR system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased particulate matter emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become particulate matter. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze. In fact, ammonium sulfates is the pollutant species representing the single greatest contribution to visibility impairment at Shenandoah National Park. Another environmental impact associated with SCR is the disposal of catalyst waste. To

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<sup>10</sup> Section 4 - *NO<sub>x</sub> Controls*, Chapter 2 *Selective Catalytic Reduction*, June 2019, p. 80 of the PDF document accessed at [https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition\\_2016revisions2017.pdf](https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).

<sup>11</sup> Section 4 - *NO<sub>x</sub> Controls*, Chapter 1 *Selective Noncatalytic Reduction*, June 2019, p. 1-54

maintain NO<sub>x</sub>-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced.

## 4.7 Costs

Table 4-3 summarizes the estimated costs, including total and annualized capital costs, annual O&M costs, and cost effectiveness based on the emission reduction values from Table 5-2 for the technically feasible NO<sub>x</sub> reduction options. The cost analysis for both controls was based on methods identified in the EPA OAQPS CCM.<sup>12</sup> These methods were supplemented by EPA-specific costing or site-specific costing, as available. Detailed information for these analyses is presented in Appendix A.

**Table 4-3. Estimated Costs of NO<sub>x</sub> Emissions Reduction Options**

<b>Emissions Unit</b>	<b>NO<sub>x</sub> Reduction Option</b>	<b>Total Annual Costs (\$/year)</b>	<b>Cost Effectiveness (\$/ton)</b>
Boiler 1	SCR	6,449,821	14,336
	SNCR	29,971,810	118,428
Boiler 2	SCR	3,882,325	25,687
	SNCR	16,677,946	196,172
Boiler 5	SCR	694,296	1,827,094
	SNCR	5,808,765	27,450,808
Boiler 6	SCR	763,098	68,872
	SNCR	5,808,765	932,337
Boiler 5/6 (Combined Stack) <sup>13</sup>	SCR	1,168,629	101,975
Boiler 7	SCR	633,468	65,781
	SNCR	4,464,920	824,022
Boiler 8	SCR	633,468	78,888
	SNCR	4,464,920	988,827

<sup>12</sup> <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost-manual>

<sup>13</sup> U. S. Steel performed a cost analysis for SCR assuming either individual SCR controls for Boilers 5 and 6 or a common SCR between where the exhaust streams combine and exit the shared stack. U. S. Steel has not evaluated technical feasibility of a shared SCR at this time based on the cost effectiveness calculation result.



## 5. SOURCE SELECTION AND ADDITIONAL FACTOR ANALYSIS

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Upon receiving the June 8, 2020 request, a comparison was performed of the source selection methods used by the Pennsylvania Department of Environmental Protection (the DEP), and carried forward by the Allegheny County Health Department (the ACHD), with other options used by regulatory agencies in other regional planning organizations (RPOs), i.e., the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) and Central States Air Resources Agencies (CenSARA). This section outlines that comparison and demonstrates that Clairton Plant would not have been subject to the four-factor analysis requirement based the more robust methods used by other agencies.

### 5.1 Regional Haze Rule Source Selection Background

The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)<sup>14</sup> provides a framework for regulatory agencies to use in development of their respective regional haze second planning period (2019-2028) implementation plans. Step 3 of the EPA's SIP Guidance is the selection of sources requiring a four-factor analysis. The methods used to select the sources requiring a four-factor analysis vary in complexity. The simplest method is based on the "Q/d" ratio, where "Q" is the magnitude, in tons per year (tpy), of visibility-impairing emissions from a source and "d" is the distance, in kilometers (km), from the source to the Class I area. As was quoted in the ACHD's August 3, 2020 letter, EPA has said a state may use Q/d as a surrogate for source visibility impacts.<sup>15</sup> However, the EPA has also previously voiced concerns over only relying on the Q/d method for screening sources. For example, the EPA points out that the Q/d metric is only a rough indicator of actual visibility impact because it does not consider transport direction/pathway and dispersion and photochemical processes.<sup>16</sup>

Because of these concerns, many RPOs and regulatory agencies have employed more robust methods for screening sources. For example, VISTAS conducted a detailed source-selection analysis using both the Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model and the Comprehensive Air Quality Model with extensions (CAMx). VISTAS' CAMx modeling made several improvements to the modeling conducted by the EPA for each state (except HI and AK) to use as part of its long-term strategy (LTS) and implementation plan development.<sup>17</sup> It ultimately used the CAMx modeling to inform the source selections being made by each of the VISTAS' states.

CenSARA also went beyond the rudimentary Q/d analysis. It developed Area of Influence (AOI) assessments for each Class I area based on HYSPLIT modeling. From these assessments, a variable known as Extinction-Weighted Residence Time (EWRT) was used to ameliorate the Q/d quotient for each source under consideration.

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<sup>14</sup> US EPA Memorandum, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period August 20, 2019. ([https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019\\_-\\_regional\\_haze\\_guidance\\_final\\_guidance.pdf](https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf))

<sup>15</sup> Ibid.

<sup>16</sup> WRAP Reasonable Progress Source Identification and Analysis Protocol for Second 10-year Regional Haze State Implementation Plans, dated February 27, 2019. (<https://www.wrapair2.org/pdf/final%20WRAP%20Reasonable%20Progress%20Source%20Identification%20and%20Analysis%20Protocol-Feb27-2019.pdf>)

<sup>17</sup> The EPA's SIP Guidance (step 6) calls for regional scale modeling, e.g. with CAMx, of the LTS to set the reasonable progress goals (RPGs) for 2028.



Neither VISTAS nor CenSARA (nor any other RPO) has responsibility for completing four-factors analyses or preparing an LTS or implementation plan. However, their approach – that is, the approach taken by the states represented by those RPOs – for determining which sources are subject to four-factor analyses provides an important point of comparison, especially if one approach proves to benefit certain sources over others.

## 5.2 Source Selection Assessment

The DEP's source selection was based on the Q/d ratio method, where "Q" was the total 2017 (for non-EGUs and 2019 for EGUs) SO<sub>2</sub> and NO<sub>x</sub> emissions for each source and "d" was the distance from each source to the Shenandoah National Park in northern Virginia (a VISTAS state). Total 2017 SO<sub>2</sub> and NO<sub>x</sub> emissions for Clairton Plant were 3,730 tpy (2,600 tpy NO<sub>x</sub> + 1,130 tpy SO<sub>2</sub>), and the distance to Shenandoah National Park is 211 km for a Q/d ratio of 17.7. Based on the Q/d ratio method, Clairton Plant ranks 6<sup>th</sup> on the list of sources evaluated by the DEP. The five sources with higher ranks are listed below:

1. Keystone with a Q/d ratio of 124.4,
2. Conemaugh with a Q/d ratio of 67.0,
3. Homer City with a Q/d ratio of 61.6,
4. Seward with a Q/d ratio of 38.1, and
5. Magnesita Refractories/York with a Q/d ratio of 25.1.

As mentioned previously, both VISTAS and CenSARA conducted more detailed source selection analyses using either HYSPLIT or CAMx modeling, or both. For the HYSPLIT modeling-based method employed by CenSARA, back trajectories of air parcels for the 20% most impaired days were used to define the areas (modeled grid cells containing source emissions) most likely to contribute to visibility impairment in the Class I areas.<sup>18,19</sup> The results of the HYSPLIT modeling were used to calculate the EWRT for sulfate and nitrate extinction. The higher the EWRT, the more likely that the air parcels passing over an area would cause extinction at the Class I area. Since this method uses the extinction value for weighting, trajectories passing over large sources are more discernible from those passing over moderate sources. The EWRT values were multiplied by each source's SO<sub>2</sub> and NO<sub>x</sub> Q/d ratio to calculate individual sulfate and nitrate EWRT\*(Q/d) values for each source. The sources were then ranked based on the sum of the sulfate and nitrate EWRT\*(Q/d) values, and the single source-specific values were normalized as a percent of total combined sulfate and nitrate EWRT\*(Q/d). Based on this methodology, the ranking of Pennsylvania sources impacting the Shenandoah National Park are as follows:

1. Keystone with a combined sulfate and nitrate EWRT\*(Q/d) of 11.93%,
2. Homer City with a combined sulfate and nitrate EWRT\*(Q/d) of 2.73%,
3. Seward with a combined sulfate and nitrate EWRT\*(Q/d) of 1.84%,
4. Conemaugh with a combined sulfate and nitrate EWRT\*(Q/d) of 1.83%,
5. Cheswick with a combined sulfate and nitrate EWRT\*(Q/d) of 0.49%, and,
6. Clairton Plant with a combined sulfate and nitrate EWRT\*(Q/d) of 0.48%.

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<sup>18</sup> Area of Influence Analysis Southeastern VISTAS II Regional Haze Analysis Project, dated December 2, 2019. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Task%205%20AOI%20Analysis%20Report%20Revised%20191202.pdf>)

<sup>19</sup> VISTAS Area of Influence Data Summary. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20AOI%20Data%20Summary.xlsx>)

Based on the ranking of all sources, both inside and outside Pennsylvania, Clairton Plant ranks 32<sup>nd</sup> on the list of sources impacting the Shenandoah National Park.

VISTAS went a step further. As a refinement to the HYSPLIT-AOI analysis results, VISTAS used CAMx modeling with the Particulate Matter Source Apportionment Technology (PSAT) option to quantify visibility impacts from individual sources, and recommended four-factor analyses for only sources with sulfate or nitrate contributions of greater than 1%.<sup>20</sup> Clairton Plant' AOI ranking was below the selection criteria for VISTAS's CAMx/PSAT modeling. That is, VISTAS deemed Clairton Plant to be insignificant with regards to carrying forward into their main source-screening method. Rather, the CAMx/PSAT modeling completed by VISTAS evaluated only three Pennsylvania sources: Keystone, Homer City, and Seward. The CAMx/PSAT sulfate modeling results for these sources were as follows:

1. Keystone with a sulfate contribution of 4.81%,
2. Homer City with a sulfate contribution of 1.78%, and
3. Seward with a sulfate contribution of 1.01%.

Note that none of the sources had nitrate contributions of greater than 1%.

These three sources are approximately 60 to 70 kilometers to the northeast of Clairton Plant, and all are a similar distance to the Shenandoah National Park. Thus, one could expect all four sources to be similar with respect to the possibility of emissions causing visibility impairment in Shenandoah National park. However, as shown below, the projected 2028 SO<sub>2</sub> emissions from Clairton Plant is significantly less than the emissions level of the three modeled facilities:

- ▶ Keystone – 21,066.37 tpy,
- ▶ Homer City – 9,274.88 tpy,
- ▶ Seward – 6,813.94 tpy, and
- ▶ U.S. Steel Clairton – 1,600 tpy.

Thus, despite the similar locations and distances to the Shenandoah National Park, based on the level of emissions, it is clear that if Clairton Plant would have been included in VISTAS' CAMx/PSAT modeling, then the visibility impacts would be less than the VISTAS source selection criteria. In other words, VISTAS would again deem Clairton Plant to not appreciably contribute to visibility impairment in that Class I area. As a result, Clairton Plant is at a disadvantage compared to sources in VISTAS states and potentially other states that adopted less robust source screening methods.

### 5.3 Status of Visibility Impairment at Shenandoah National Park

Visibility impairment or "haze" is described by the light extinction visibility metric in units of inverse megameters (Mm<sup>-1</sup>). Because the inverse-distance units are difficult to conceptualize, the deciview haze index (dv) was developed. Extinction values are converted to deciviews using a logarithmic equation<sup>21</sup> such that the deciview scale is nearly zero for a pristine atmosphere, and, like the decibel scale for sound,

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<sup>20</sup> VISTAS Regional Haze Project Update, Stackholder Briefing by Jim Boylan, dated May 20, 2020. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf>). It is acknowledged that subsequent modeling was performed as noted in an August 4, 2020 project update by Jim Boylan.

<sup>21</sup> Deciview = 10 × ln (Extinction ÷ 10)

equivalent changes in deciviews are perceived similarly across a wide range of background conditions.<sup>22</sup> Light extinction in the Class I areas is observed via the Interagency Monitoring of Protected Visual Environments (IMPROVE) network of Class I area air monitors. IMPROVE visibility data are available on the IMPROVE website.

Step 5 of the SIP Guidance is the decision on what control measures are necessary to make reasonable progress towards natural visibility conditions in 2064.<sup>23</sup> The progress for each Class I area is measured by comparing the IMPROVE monitoring data to the area's Uniform Rate of Progress ("URP") or "glidepath", which is a straight line from baseline visibility conditions (average of the 20 percent most impaired days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent most impaired days).<sup>24</sup>

Step 6 of the SIP Guidance is regional scale modeling of the long-term strategy (LTS) to set the reasonable progress goals (RPGs) for 2028. Both the EPA<sup>25</sup> and VISTAS<sup>26</sup> have conducted CAMx modeling showing the projected 2028 haze index is below the 2028 URP. The projected 2028 visibility impacts are based on projected 2028 emissions. The VISTAS and EPA modeling used EPA's 2011v6.3 and EPA's 2016v7.3 (beta and Regional Haze) modeling platforms, respectively. These platforms used 2011 base year emissions and 2016 base year emissions, respectively. For non-Electrical Generating Units, such as Clairton Plant, the modeled 2028 emissions were set equal to the base year emissions.

Figure 1 presents a comparison of IMPROVE's annual-average haze index values for the most impaired days at Shenandoah National Park to the URP proposed by the EPA. As seen in Figure 1, the observed visibility impairment at Shenandoah National Park has declined sharply and continues to trend downward. Thus, the current Class I area visibility conditions are better than necessary (or ahead of schedule) to achieve the goal of the regional haze program. In addition, the projected (modeled) 2028 haze index values from the EPA modeling are shown in Figure 1. EPA's modeling shows the projected 2028 haze index values are satisfying the objective of the Regional Haze Program by improving the most impaired days and no additional degradation to the clearest days. Lastly, the projected 2028 most-impaired days value from VISTAS modeling (as of August 2020) is also shown in Figure 1.<sup>27</sup> It also indicates that the 2028 projected visibility impairment at Shenandoah National Park is below the glidepath and on pace to achieve the 2064 goal about twenty (20) years ahead of schedule.

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<sup>22</sup> U.S. EPA, Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress at 1-5 - 1-7 (November 2001).

<sup>23</sup> Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

<sup>24</sup> This URP definition differs from that used in the first planning period (2004-2018). Per the EPA's Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, December 2018, EPA-454/R-18-010, only anthropogenic (manmade) impairment is considered; thus, the URP is based on the 20% most impaired days rather than the 20% worst days. Note, however, that the tracking of the 20 percent clearest days remains unchanged.

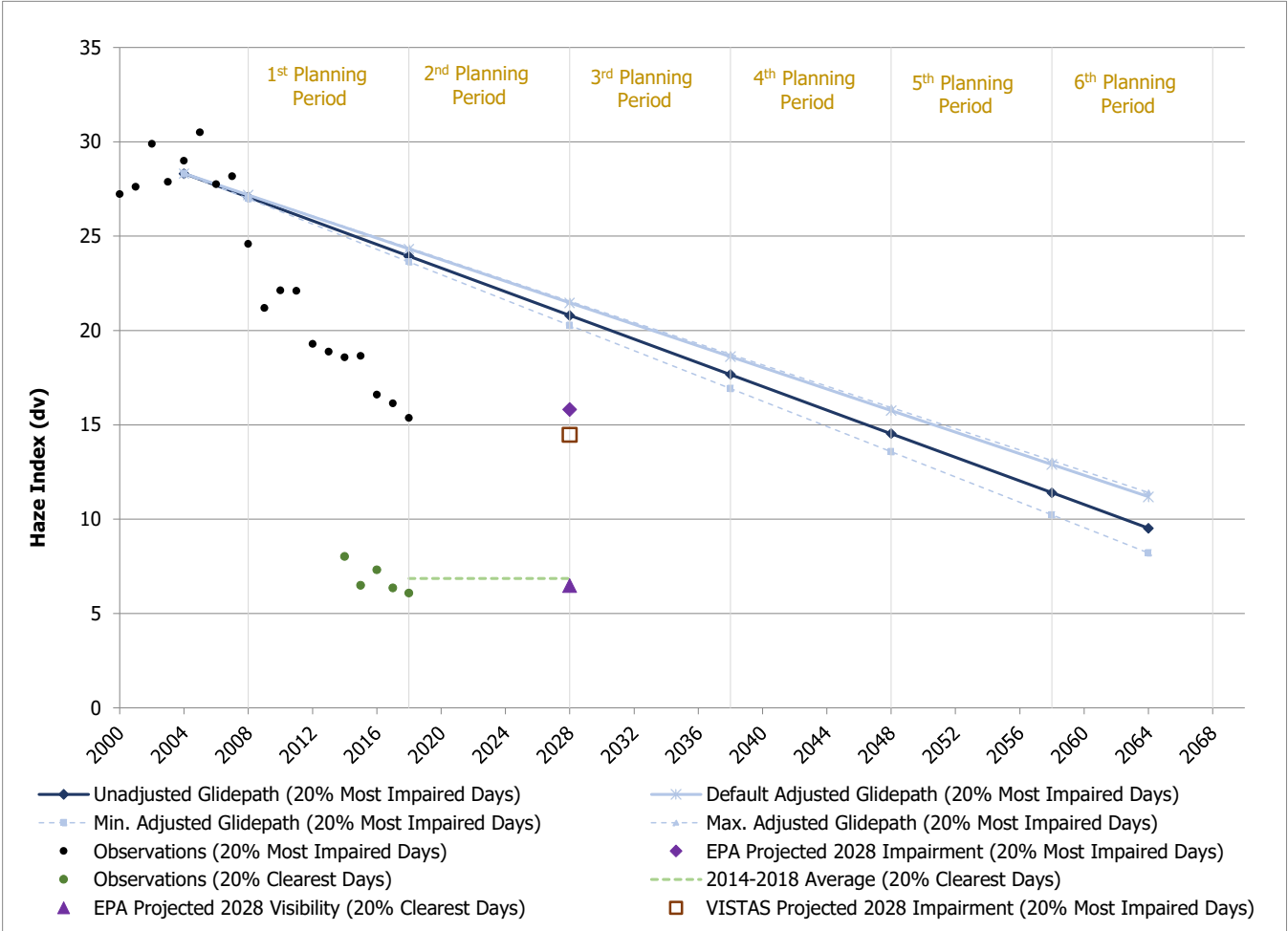
<sup>25</sup> Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, September 19, 2019. ([https://www.epa.gov/sites/production/files/2019-10/documents/updated\\_2028\\_regional\\_haze\\_modeling-tsd-2019\\_0.pdf](https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf))

<sup>26</sup> VISTAS Regional Haze Project Update, Stakeholder Briefing by Jim Boylan, dated May 20, 2020. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf>). It is acknowledged that subsequent modeling was performed as noted in an August 4, 2020 project update by Jim Boylan. That reassessment did not change the ultimately conclusions with respect to Shenandoah National Park and future goals.

<sup>27</sup> Ibid.

Therefore, the current projected 2028 emissions, which include Clairton Plant emitting at its current level in 2028, contain sufficient reductions to show reasonable progress. Going further and requiring additional control beyond that required specifically for this round of rulemaking could put unreasonable burden on Pennsylvania’s sources if other states ultimately delay their control requirements.

**Figure 1. Visibility Observations Compared to Glidepaths for Shenandoah National Park**



## 6. CONCLUSION

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U. S. Steel has complied with the agency's request to conduct a four-factor analysis for the Clairton Plant. The four-factor analysis detailed possible SO<sub>2</sub> and NO<sub>x</sub> emission reduction technologies and considered, amongst other elements, technical and economic feasibility. As shown in Sections 3.7 and 4.7, any potential technically feasible controls were found to be economically infeasible at the Clairton Plant.

In addition, the observed visibility impairment at Shenandoah National Park has declined sharply and continues to trend downward, and the EPA and VISTAS modeling both indicate that the 2028 projected visibility impairment at Shenandoah National Park is below the glidepath. Moreover, based on the CenSARA and VISTAS HYSPLIT analyses and VISTAS' CAMx/PSAT modeling it is clear that Clairton Plant does not appreciably affect visibility at Shenandoah National Park and that any emissions reductions at Clairton Plant would be insignificant according to the standard used by the RPO charged with overseeing Shenandoah National Park. U. S. Steel believes that the above information, as more thoroughly detailed in Section 5, is sufficient justification to demonstrate that even-if the four-factor analysis resulted in a technologically and economically feasible control option, it would be unreasonable for the PADEP and ACHD to require the Clairton Plant to install such technology.

## Appendix A. CONTROL COST STUDIES

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**SCR Costs for Boilers**

<b>Source</b>	<b>Annualized Costs (\$/yr)</b>	<b>Emissions Reduction (tpy)</b>	<b>Cost Effectiveness (\$/ton)</b>
Boiler 1	6,449,821	449.90	14,336
Boiler 2	3,882,325	151.14	25,687
Boiler 5	694,296	0.38	1,827,094
Boiler 6	763,098	11.08	68,872
Boiler 5/6	1,168,629	11.46	101,975
Boiler 7	633,468	9.63	65,781
Boiler 8	633,468	8.03	78,888

## Heat Capacity Boiler Combustion Stack Gas

	BOILER #1		BOILER #2		BOILER #R1		BOILER #R2		BOILER #T1		BOILER #T2	
	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)
H2O	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225
O2	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185
CO2	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260
N2	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185
<b>Total</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>

	BOILER #1	BOILER #2	BOILER #R1	BOILER #R2	BOILER #T1	BOILER #T2
Flow (1)	176,746 scfm	110,617 scfm	29,315 scfm	29,315 scfm	25,142 scfm	25,142 scfm
Flow	<b>1.06E+07 scfh</b>	<b>6.64E+06 scfh</b>	<b>1.76E+06 scfh</b>	<b>1.76E+06 scfh</b>	<b>1.51E+06 scfh</b>	<b>1.51E+06 scfh</b>
Temperature <sub>SCR in</sub> (1)	<b>313 F</b>	<b>326 F</b>	<b>491.9 F</b>	<b>491.9 F</b>	<b>473.5 F</b>	<b>473.5 F</b>
Temperature <sub>SCR out</sub> (2)	<b>730 F</b>	<b>730 F</b>	<b>730 F</b>	<b>730 F</b>	<b>730 F</b>	<b>730 F</b>
ΔT	<b>417 F</b>	<b>404 F</b>	<b>238.1 F</b>	<b>238.1 F</b>	<b>256.5 F</b>	<b>256.5 F</b>
Heat Requirement	8.0 Btu/scf	7.7 Btu/scf	4.5 Btu/scf	4.5 Btu/scf	4.9 Btu/scf	4.9 Btu/scf
Natural Gas Eff'y	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
Natural Gas Req'd	10.0 Btu / scf flue gas	9.6 Btu / scf flue gas	5.7 Btu / scf flue gas	5.7 Btu / scf flue gas	6.1 Btu / scf flue gas	6.1 Btu / scf flue gas
Natural Gas Req'd	9.95E-06 MMBtu/scf flue gas	9.64E-06 MMBtu/scf flue gas	5.68E-06 MMBtu/scf flue gas	5.68E-06 MMBtu/scf flue gas	6.12E-06 MMBtu/scf flue gas	6.12E-06 MMBtu/scf flue gas
Natural Gas Cost (4)	\$7.36 / MMBtu	\$7.36 / MMBtu	\$7.36 / MMBtu	\$7.36 / MMBtu	\$7.36 / MMBtu	\$7.36 / MMBtu
2017 Hours of Operation	5,280 Hr/yr	4,928 Hr/yr	29 Hr/yr	732 Hr/yr	1,028 Hr/yr	1,028 Hr/yr
Annual Natural Gas Cost (5)	\$4,100,927	\$2,320,923	\$2,156	\$53,866	\$69,889	\$69,889

(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) EIA 2019 average NG prices for commercial consumers in 2019 ([https://www.eia.gov/naturalgas/monthly/pdf/table\\_03.pdf](https://www.eia.gov/naturalgas/monthly/pdf/table_03.pdf))

(5) Annual NG Cost = \$/MMBtu NG x MMBtu/scf flue gas x scf flue gas/hr x hrs/yr



### SCR Design Parameters used for Estimation

Boiler #1 Max. Heat Input,  $Q_B =$  760 MMBtu/hr

System Capacity Factor,  $CF_{total} = CF_{plant} \times CF_{SCR}$

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

	Actual	458.1	MMBtu/hr
	Potential	760	MMBtu/hr
CFBoiler2=	0.60		
	$t_{SCR}$	365	days/yr
$CF_{SCR} =$	1.00		
$CF_{total} =$	0.60		

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)= 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T$$

(As per pg. 1-24 of SCR manual)

$$SR_T = \frac{1}{\text{(Ratio of equivalent moles of } NH_3 \text{ per mole of reagent injected.)}}$$
$$NSR = 1.05$$

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 273,000 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 5460 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 1365 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

$$Vol_{catalyst} = \frac{-\left(q_{fluegas} \times \ln\left[1 - \left(\frac{\eta_{NOx}}{ASR}\right)\right]\right)}{K_{catalyst} \times A_{specific}}$$
  
 $Vol_{catalyst} = Vol_{reactor} = 5460$

SCR Reactor Dimensions

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

$A_{catalyst} = 284.4 \text{ ft}^2$

$A_{SCR} = 1.15 \times A_{catalyst}$   
$$\begin{aligned} A_{SCR} &= 327.0 \text{ ft}^2 \\ l_{scr} &= 18.1 \text{ ft} \\ w_{scr} &= 18.1 \text{ ft} \end{aligned}$$

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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

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

#### Estimating Reagent Consumption and Tank Size

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

$NO_{X_{in}} =$	0.54	lb/MMBtu
$Q_B =$	760	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	127.6	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	671.6	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	89.7	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	30144	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3rate) = \left[ \frac{\$399.0}{lb/hr} \frac{\dot{m}_{reagent}}{Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 5,460.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 1310400$$

$$\text{Direct Capital, DC} = \$ 9,673,089 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 1,934,618 \\&= \text{DC} \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%}) \\&\quad \text{General Facilities \%} = 5\% \\&\quad \text{Engineering and Home Office Fees \%} = 10\% \\&\quad \text{Process Contingency \%} = 5\% \\ \\ \text{Project Contingency, C} &= \$ 1,741,156.05 \\&\quad = 15\% \text{ of DC + IC} \\ \\ \text{Total Plant Cost, D} &= \$ 13,348,863.06 = \text{DC} + \text{IC} + \text{C} \\ \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Preproduction Costs, G} &= \$ 266,977.26 \\&\quad = 2\% \text{ of D + E} \\ \\ \text{Inventory Capital, H} &= \$ 14,439.16 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\&\quad \text{Vol}_{\text{reagent}} = 30144 \text{ gal/yr} \\&\quad \text{Cost}_{\text{reagent}} = 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Total Capital Investment, TCI} &= \$ 13,630,279.48 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

### Operating and Supervisory Labor:

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

### Maintenance:

$$\text{Maintenance} = 1.5\% \text{ of TCI} = \$ 204,454$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 5280 \text{ hours}$$

### Reagent Consumption:

$$\begin{aligned} \text{cost}_{\text{reagent}} &= 0.479 \text{ \$/gallon} \\ \text{Annual reagent cost} &= \$ 226,886 = q_{\text{reagent}} \times \text{cost}_{\text{reagent}} \times t_{\text{op}} \end{aligned}$$

### Utilities:

$$Power = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$DP_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$DP_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$Power = 329.5$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 5280 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 121,790$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$\begin{aligned} R_{\text{layer}} &= 1 && \text{for full replacement} \\ R_{\text{layer}} &= 6.2 && = n_{\text{layer}} \text{ (for replacing one layer per year)} \\ n_{\text{SCR}} &= 1 && \text{(number of SCR reactors per boiler)} \end{aligned}$$

$$\text{Catalyst Replacement Cost} = \$ 1,932,797.95 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57})$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 5$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 5280 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.19$$

$$\text{Annual Catalyst Replacement Cost} = \$ 369,164$$

$$\text{Total DAC} = \$ 5,023,222$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\begin{aligned} \text{Interest rate, } i &= 8.00\% && \text{US Steel specific rate} \\ \text{Economic life of SNCR, } n &= 20 && \text{years} \\ \text{CRF} &= 0.102 \end{aligned}$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 13,630,279.48$$

$$\text{IDAC} = \$ 1,388,274$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 6,411,496.10$$



**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #1**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**5280**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**760**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**330**

Reagent sol, gal/hr

**89.7**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

**30144**

Reagent Cost, \$/gallon

**0.48**

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #1**

**NOX Emission Control Option: SCR (80% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 9,673,089	<b>Direct Annual Costs</b>		Efficiency, %	80%
Auxilliary Equipment (Heat Exchanger)	\$ -	Operating & Supervisory Labor	\$38,325	Boiler Heat Input, MMBtu/hr	760
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, and freight. Cost for sales tax and heat exchanger not included.		Maintenance	\$204,454	Total Operating Time, hrs/yr	5280
		Reagent Consumption	\$226,886		
		Utilities	\$121,790		
		Catalyst Replacement	\$369,164	NO <sub>x</sub> removed, tpy	449.9
Total Indirect Capital Costs:		Auxilliary Equipment Requirements	\$4,100,927		
Indirect Capital, IC	\$ 1,934,618	gas cost required to heat boiler			
Project Contingency, C	\$ 1,741,156	exhaust up to SCR required			
		temperature.)			
Total Plant Cost, D (DC + IC + C)	\$13,348,863				
		Total Direct Annual Costs	\$5,061,547		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>		<b>\$/ton NO<sub>x</sub> removed</b>	<b>\$ 14,336</b>
Preproduction Costs, G	\$ 266,977	CRF	0.10185		
Inventory Capital, H	\$ 14,439	IDAC (CRF x TCI)	\$1,388,274		
Initial Catalyst and Chemicals, I	\$ -				
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 13,630,279</b>	<b>TOTAL ANNUAL COST, TAC</b>	<b>\$6,449,821</b>		

### SCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input,  $Q_B =$  481 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.

	Actual	270.6	MMBtu/hr
	Potential	481	MMBtu/hr
CFBoiler2=	0.56		
	$t_{SCR}$	365	days/yr
$CF_{SCR} =$	1.00		
$CF_{total} =$	0.56		

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)= 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T$$

(As per pg. 1-24 of SCR manual)

$SR_T =$  1 (Ratio of equivalent moles of  $NH_3$  per mole of reagent injected.)

NSR = 1.05

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 155,000 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 3100 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 775 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor} = 3100$

SCR Reactor Dimensions

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

$A_{catalyst} = 161.5 \text{ ft}^2$

$$\begin{aligned} A_{SCR} &= 1.15 \times A_{catalyst} \\ A_{SCR} &= 185.7 \text{ ft}^2 \\ l_{scr} &= 13.6 \text{ ft} \\ w_{scr} &= 13.6 \text{ ft} \end{aligned}$$

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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

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

#### Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{Xin} \times Q_B \times NSR \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X} \times SR_T}$$

$NO_{Xin} =$	0.54	lb/MMBtu
$Q_B =$	481	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	80.8	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	425.0	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	56.8	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	19078	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[ \frac{\$399.0 \dot{m}_{reagent}}{lb/hr - Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3 rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 3,100.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 744000$$

$$\text{Direct Capital, DC} = \$ 6,827,348 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 1,365,470 \\&= \text{DC} \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%}) \\&\quad \text{General Facilities \%} = 5\% \\&\quad \text{Engineering and Home Office Fees \%} = 10\% \\&\quad \text{Process Contingency \%} = 5\% \\ \\ \text{Project Contingency, C} &= \$ 1,228,922.61 \\&= 15\% \text{ of DC + IC} \\ \\ \text{Total Plant Cost, D} &= \$ 9,421,739.97 = \text{DC} + \text{IC} + \text{C} \\ \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Preproduction Costs, G} &= \$ 188,434.80 \\&= 2\% \text{ of D + E} \\ \\ \text{Inventory Capital, H} &= \$ 9,138.47 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\&\quad \text{Vol}_{\text{reagent}} = 19078 \text{ gal/yr} \\&\quad \text{Cost}_{\text{reagent}} = 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Total Capital Investment, TCI} &= \$ 9,619,313.24 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

#### Operating and Supervisory Labor:

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

#### Maintenance:

$$\begin{aligned} & 1.5\% \text{ of TCI} \\ \text{Maintenance} &= \$ 144,290 \end{aligned}$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 4928 \text{ hours}$$

#### Reagent Consumption:

$$\begin{aligned} & \text{cost}_{\text{reagent}} = 0.479 \text{ \$/gallon} \\ \text{Annual reagent cost} &= \$ 134,030 = q_{\text{reagent}} \times \text{cost}_{\text{reagent}} \times t_{\text{op}} \end{aligned}$$

#### Utilities:

$$Power = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$DP_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$DP_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$\text{Power} = 208.6$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 4928 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 71,946$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$\begin{aligned} R_{\text{layer}} &= 1 && \text{for full replacement} \\ R_{\text{layer}} &= 6.2 && = n_{\text{layer}} \text{ (for replacing one layer per year)} \\ n_{\text{SCR}} &= 1 && \text{(number of SCR reactors per boiler)} \end{aligned}$$

$$\text{Catalyst Replacement Cost} = \$ 1,097,376.12 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57})$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 5$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 4928 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.18$$

$$\text{Annual Catalyst Replacement Cost} = \$ 193,064$$

$$\text{Total DAC} = \$ 4,644,256$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\begin{aligned} \text{Interest rate, } i &= 8.00\% && \text{US Steel specific rate} \\ \text{Economic life of SNCR, } n &= 20 && \text{years} \\ \text{CRF} &= 0.102 \end{aligned}$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 9,619,313.24$$

$$\text{IDAC} = \$ 979,748$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 5,624,004.39$$

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #2**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**4928**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**481**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**209**

Reagent sol, gal/hr

**56.8**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

**19078**

Reagent Cost, \$/gallon

**0.48**

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #2**

**NOX Emission Control Option: SCR (80% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 6,827,348	<b>Direct Annual Costs</b>		Efficiency, %	80%
Auxilliary Equipment (Heat Exchanger)	\$ -	Operating & Supervisory Labor	\$38,325	Boiler Heat Input, MMBtu/hr	481
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, and freight. Cost for sales tax and heat exchanger not included.		Maintenance	\$144,290	Total Operating Time, hrs/yr	4928
		Reagent Consumption	\$134,030		
		Utilities	\$71,946	NO <sub>x</sub> removed, tpy	151.1
		Catalyst Replacement	\$193,064		
Total Indirect Capital Costs:		Auxilliary Equipment Requirements	\$2,320,923		
Indirect Capital, IC	\$ 1,365,470	gas cost required to heat boiler			
Project Contingency, C	\$ 1,228,923	exhaust up to SCR required			
		temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 9,421,740				
		Total Direct Annual Costs	\$2,902,577		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>		<b>\$/ton NO<sub>x</sub> removed</b>	<b>\$ 25,687</b>
Preproduction Costs, G	\$ 188,435	CRF	0.10185		
Inventory Capital, H	\$ 9,138	IDAC (CRF x TCI)	\$979,748		
Initial Catalyst and Chemicals, I	\$ -				
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 9,619,313</b>	<b>TOTAL ANNUAL COST, TAC</b>	<b>\$3,882,325</b>		

### SCR Design Parameters used for Estimation

Boiler #5 & #6 Max. Heat Input,  $Q_B =$  458 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.

	Actual	19.9	MMBtu/hr
	Potential	458	MMBtu/hr
CFBoiler2=	0.04		
	$t_{SCR}$	365	days/yr
$CF_{SCR} =$	1.00		
$CF_{total} =$	0.04		

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)= 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T$$

(As per pg. 1-24 of SCR manual)

$SR_T =$  1 (Ratio of equivalent moles of  $NH_3$  per mole of reagent injected.)

$NSR =$  1.05

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 125,600 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 2512 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 628 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor} = 2512$

SCR Reactor Dimensions

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

$A_{catalyst} = 130.8 \text{ ft}^2$

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

$$\begin{aligned} A_{SCR} &= 150.5 \text{ ft}^2 \\ l_{scr} &= 12.3 \text{ ft} \\ w_{scr} &= 12.3 \text{ ft} \end{aligned}$$

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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

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

#### Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{Xin} \times Q_B \times NSR \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X} \times SR_T}$$

$NO_{Xin} =$	0.54	lb/MMBtu
$Q_B =$	458	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	76.9	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	404.7	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	54.1	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	18166	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[ \frac{\$399.0 \dot{m}_{reagent}}{lb/hr - Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3 rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 2,512.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 602880$$

$$\text{Direct Capital, DC} = \$ 6,429,603 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 1,285,921 \\ \text{=DC x (General Facilities \% + Engineering and Home Office Fees \% + Process Contingency \%)} \\ \text{General Facilities \%} &= 5\% \\ \text{Engineering and Home Office Fees \%} &= 10\% \\ \text{Process Contingency \%} &= 5\% \\ \\ \text{Project Contingency, C} &= \$ 1,157,328.55 \\ &= 15\% \text{ of DC + IC} \\ \\ \text{Total Plant Cost, D} &= \$ 8,872,852.18 = \text{DC} + \text{IC} + \text{C} \\ \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Preproduction Costs, G} &= \$ 177,457.04 \\ &= 2\% \text{ of D + E} \\ \\ \text{Inventory Capital, H} &= \$ 8,701.49 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\ \text{Vol}_{\text{reagent}} &= 18166 \text{ gal/yr} \\ \text{Cost}_{\text{reagent}} &= 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Total Capital Investment, TCI} &= \$ 9,059,010.72 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

#### Operating and Supervisory Labor:

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

#### Maintenance:

$$\begin{aligned} & 1.5\% \text{ of TCI} \\ \text{Maintenance} &= \$ 135,885 \end{aligned}$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 381 \text{ hours}$$

#### Reagent Consumption:

$$\begin{aligned} & \text{cost}_{\text{reagent}} = 0.479 \text{ \$/gallon} \\ \text{Annual reagent cost} &= \$ 9,862 = q_{\text{reagent}} \times \text{cost}_{\text{reagent}} \times t_{\text{op}} \end{aligned}$$

#### Utilities:

$$Power = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$DP_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$DP_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$\text{Power} = 198.6$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 381 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 5,294$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$R_{\text{layer}} = 1 \quad \text{for full replacement}$$

$$R_{\text{layer}} = 6.2 \quad = n_{\text{layer}} \text{ (for replacing one layer per year)}$$

$$n_{\text{SCR}} = 1 \quad \text{(number of SCR reactors per boiler)}$$

$$\text{Catalyst Replacement Cost} = \$ 889,228.65 \quad \text{(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57)}$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 63$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 381 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.00$$

$$\text{Annual Catalyst Replacement Cost} = \$ 561$$

$$\text{Total DAC} = \$ 4,252,528$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Economic life of SNCR, } n = 20 \quad \text{years}$$

$$\text{CRF} = 0.102$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 9,059,010.72$$

$$\text{IDAC} = \$ 922,680$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 5,175,208.34$$

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #5 & #6**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**381**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**458**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**199**

Reagent sol, gal/hr

**54.1**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

**18166**

Reagent Cost, \$/gallon

**0.48**

### NOX Emission Control Option: SCR (80% Efficiency)

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### SCR Design Parameters used for Estimation

Boiler #5 Max. Heat Input,  $Q_B =$  229 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.

Actual	0.8	MMBtu/hr
Potential	229	MMBtu/hr

$CF_{Boiler2} =$  0.00

$t_{SCR}$  365 days/yr

$CF_{SCR} =$  1.00

$CF_{total} =$  0.00

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled) = 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T$$

(As per pg. 1-24 of SCR manual)

$SR_T =$  1 (Ratio of equivalent moles of  $NH_3$  per mole of reagent injected.)

$NSR =$  1.05

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 62,800 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 1256 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 314 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor} = 1256$

SCR Reactor Dimensions

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

$A_{catalyst} = 65.4 \text{ ft}^2$

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

$$\begin{aligned} A_{SCR} &= 75.2 \text{ ft}^2 \\ l_{scr} &= 8.7 \text{ ft} \\ w_{scr} &= 8.7 \text{ ft} \end{aligned}$$



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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

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

#### Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{Xin} \times Q_B \times NSR \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X} \times SR_T}$$

$NO_{Xin} =$	0.54	lb/MMBtu
$Q_B =$	229	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	38.4	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	202.4	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	27.0	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	9083	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[ \frac{\$399.0 \dot{m}_{reagent}}{lb/hr - Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3 rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 1,256.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 301440$$

$$\text{Direct Capital, DC} = \$ 3,968,374 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 793,675 \\ &= \text{DC} \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%}) \\ \text{General Facilities \%} &= 5\% \\ \text{Engineering and Home Office Fees \%} &= 10\% \\ \text{Process Contingency \%} &= 5\% \\ \\ \text{Project Contingency, C} &= \$ 714,307.28 \\ &= 15\% \text{ of DC + IC} \\ \\ \text{Total Plant Cost, D} &= \$ 5,476,355.83 = \text{DC} + \text{IC} + \text{C} \\ \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Preproduction Costs, G} &= \$ 109,527.12 \\ &= 2\% \text{ of D + E} \\ \\ \text{Inventory Capital, H} &= \$ 4,350.75 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\ \text{Vol}_{\text{reagent}} &= 9083 \text{ gal/yr} \\ \text{Cost}_{\text{reagent}} &= 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Total Capital Investment, TCI} &= \$ 5,590,233.69 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

### Operating and Supervisory Labor:

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

### Maintenance:

$$\text{Maintenance} = 1.5\% \text{ of TCI} \\ \text{Maintenance} = \$ 83,854$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 29 \text{ hours}$$

### Reagent Consumption:

$$\text{Annual reagent cost} = \text{cost}_{\text{reagent}} \times q_{\text{reagent}} \times t_{\text{op}} \\ \text{Annual reagent cost} = \$ 380$$

### Utilities:

$$Power = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$DP_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$DP_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$\text{Power} = 99.3$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 29 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 204$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$\begin{aligned} R_{\text{layer}} &= 1 && \text{for full replacement} \\ R_{\text{layer}} &= 6.2 && = n_{\text{layer}} \text{ (for replacing one layer per year)} \\ n_{\text{SCR}} &= 1 && \text{(number of SCR reactors per boiler)} \end{aligned}$$

$$\text{Catalyst Replacement Cost} = \$ 444,614.33 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57})$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 819$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 29 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.00$$

$$\text{Annual Catalyst Replacement Cost} = \$ 0$$

$$\text{Total DAC} = \$ 4,185,364$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\begin{aligned} \text{Interest rate, } i &= 8.00\% && \text{US Steel specific rate} \\ \text{Economic life of SNCR, } n &= 20 && \text{years} \\ \text{CRF} &= 0.102 \end{aligned}$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 5,590,233.69$$

$$\text{IDAC} = \$ 569,378$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 4,754,741.31$$

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #5**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**29**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**229**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**99**

Reagent sol, gal/hr

**27.0**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

**9083**

Reagent Cost, \$/gallon

**0.48**

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #5**

**NOX Emission Control Option: SCR (80% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 3,968,374	<b>Direct Annual Costs</b>		Efficiency, %	80%
Auxilliary Equipment (Heat Exchanger)	\$ -	Operating & Supervisory Labor	\$38,325	Boiler Heat Input, MMBtu/hr	229
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, and freight. Cost for sales tax and heat exchanger not included.		Maintenance	\$83,854	Total Operating Time, hrs/yr	29
		Reagent Consumption	\$380		
		Utilities	\$204		
		Catalyst Replacement	\$0	NO <sub>x</sub> removed, tpy	0.4
Total Indirect Capital Costs:		Auxilliary Equipment Requirements	\$2,156		
Indirect Capital, IC	\$ 793,675	gas cost required to heat boiler			
Project Contingency, C	\$ 714,307	exhaust up to SCR required			
		temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 5,476,356				
		Total Direct Annual Costs	\$124,918		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -			\$/ton NO <sub>x</sub> removed	\$ 1,827,094
Preproduction Costs, G	\$ 109,527	<b>Indirect Annual Costs</b>			
Inventory Capital, H	\$ 4,351	CRF 0.10185			
Initial Catalyst and Chemicals, I	\$ -	IDAC (CRF x TCI)	\$569,378		
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 5,590,234</b>	<b>TOTAL ANNUAL COST, TAC</b>	<b>\$694,296</b>		



### SCR Design Parameters used for Estimation

Boiler #6 Max. Heat Input,  $Q_B =$  229 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.

	Actual	19.1	MMBtu/hr
	Potential	229	MMBtu/hr
CFBoiler2=	0.08		
	$t_{SCR}$	365	days/yr
$CF_{SCR} =$	1.00		
$CF_{total} =$	0.08		

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)= 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T$$

(As per pg. 1-24 of SCR manual)

$$SR_T = \frac{1}{\text{(Ratio of equivalent moles of } NH_3 \text{ per mole of reagent injected.)}}$$
$$NSR = 1.05$$

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 62,800 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 1256 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 314 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor} = 1256$

SCR Reactor Dimensions

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

$A_{catalyst} = 65.4 \text{ ft}^2$

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

$$\begin{aligned} A_{SCR} &= 75.2 \text{ ft}^2 \\ l_{scr} &= 8.7 \text{ ft} \\ w_{scr} &= 8.7 \text{ ft} \end{aligned}$$

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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

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

#### Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{Xin} \times Q_B \times NSR \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X} \times SR_T}$$

$NO_{Xin} =$	0.54	lb/MMBtu
$Q_B =$	229	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	38.4	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	202.4	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	27.0	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	9083	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[ \frac{\$399.0 \dot{m}_{reagent}}{lb/hr - Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3 rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 1,256.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 301440$$

$$\text{Direct Capital, DC} = \$ 3,968,374 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 793,675 \\ &= \text{DC} \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%}) \\ \text{General Facilities \%} &= 5\% \\ \text{Engineering and Home Office Fees \%} &= 10\% \\ \text{Process Contingency \%} &= 5\% \\ \\ \text{Project Contingency, C} &= \$ 714,307.28 \\ &= 15\% \text{ of DC + IC} \\ \\ \text{Total Plant Cost, D} &= \$ 5,476,355.83 = \text{DC} + \text{IC} + \text{C} \\ \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Preproduction Costs, G} &= \$ 109,527.12 \\ &= 2\% \text{ of D + E} \\ \\ \text{Inventory Capital, H} &= \$ 4,350.75 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\ \text{Vol}_{\text{reagent}} &= 9083 \text{ gal/yr} \\ \text{Cost}_{\text{reagent}} &= 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Total Capital Investment, TCI} &= \$ 5,590,233.69 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

### Operating and Supervisory Labor:

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

### Maintenance:

$$\text{Maintenance} = 1.5\% \text{ of TCI} = \$ 83,854$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 732 \text{ hours}$$

### Reagent Consumption:

$$\begin{aligned} \text{cost}_{\text{reagent}} &= 0.479 \text{ \$/gallon} \\ \text{Annual reagent cost} &= \$ 9,482 = q_{\text{reagent}} \times \text{cost}_{\text{reagent}} \times t_{\text{op}} \end{aligned}$$

### Utilities:

$$Power = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$DP_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$DP_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$Power = 99.3$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 732 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 5,090$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$\begin{aligned} R_{\text{layer}} &= 1 && \text{for full replacement} \\ R_{\text{layer}} &= 6.2 && = n_{\text{layer}} \text{ (for replacing one layer per year)} \\ n_{\text{SCR}} &= 1 && \text{(number of SCR reactors per boiler)} \end{aligned}$$

$$\text{Catalyst Replacement Cost} = \$ 444,614.33 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57})$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 33$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 732 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.01$$

$$\text{Annual Catalyst Replacement Cost} = \$ 3,104$$

$$\text{Total DAC} = \$ 4,202,456$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\begin{aligned} \text{Interest rate, } i &= 8.00\% && \text{US Steel specific rate} \\ \text{Economic life of SNCR, } n &= 20 && \text{years} \\ \text{CRF} &= 0.102 \end{aligned}$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 5,590,233.69$$

$$\text{IDAC} = \$ 569,378$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 4,771,834.11$$



**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #6**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**732**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**229**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**99**

Reagent sol, gal/hr

**27.0**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

**9083**

Reagent Cost, \$/gallon

**0.48**

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #6**

**NOX Emission Control Option: SCR (80% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 3,968,374	<b>Direct Annual Costs</b>		Efficiency, %	80%
Auxilliary Equipment (Heat Exchanger)	\$ -	Operating & Supervisory Labor	\$38,325	Boiler Heat Input, MMBtu/hr	229
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, and freight. Cost for sales tax and heat exchanger not included.		Maintenance	\$83,854	Total Operating Time, hrs/yr	732
		Reagent Consumption	\$9,482		
		Utilities	\$5,090		
		Catalyst Replacement	\$3,104	NO <sub>x</sub> removed, tpy	11.1
Total Indirect Capital Costs:		Auxilliary Equipment Requirements	\$53,866		
Indirect Capital, IC	\$ 793,675	gas cost required to heat boiler			
Project Contingency, C	\$ 714,307	exhaust up to SCR required			
		temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 5,476,356				
		Total Direct Annual Costs	\$193,721		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>		\$/ton NO <sub>x</sub> removed	\$ 68,872
Preproduction Costs, G	\$ 109,527				
Inventory Capital, H	\$ 4,351	CRF 0.10185			
Initial Catalyst and Chemicals, I	\$ -	IDAC (CRF x TCI)	\$569,378		
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 5,590,234</b>	<b>TOTAL ANNUAL COST, TAC</b>	<b>\$763,098</b>		

### SCR Design Parameters used for Estimation

Boiler #7 Max. Heat Input,  $Q_B =$  156 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.

	Actual	18.3	MMBtu/hr
	Potential	156	MMBtu/hr
CFBoiler2=	0.12		
	$t_{SCR}$	365	days/yr
$CF_{SCR} =$	1.00		
$CF_{total} =$	0.12		

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)= 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T \quad \begin{array}{l} \text{(As per pg. 1-24 of SCR manual)} \\ SR_T = \frac{1}{\text{(Ratio of equivalent moles of } NH_3 \text{ per mole of reagent injected.)}} \end{array}$$

NSR = 1.05

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 46,600 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 932 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 233 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor} = 932$

SCR Reactor Dimensions

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

$A_{catalyst} = 48.5 \text{ ft}^2$

$$\begin{aligned} A_{SCR} &= 1.15 \times A_{catalyst} \\ A_{SCR} &= 55.8 \text{ ft}^2 \\ l_{scr} &= 7.5 \text{ ft} \\ w_{scr} &= 7.5 \text{ ft} \end{aligned}$$

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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

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

#### Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{Xin} \times Q_B \times NSR \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X} \times SR_T}$$

$NO_{Xin} =$	0.54	lb/MMBtu
$Q_B =$	156	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	26.2	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	137.8	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	18.4	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	6188	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[ \frac{\$399.0 \dot{m}_{reagent}}{lb/hr - Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3 rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 932.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 223680$$

$$\text{Direct Capital, DC} = \$ 3,074,616 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 614,923 \\ &= \text{DC} \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%}) \\ \text{General Facilities \%} &= 5\% \\ \text{Engineering and Home Office Fees \%} &= 10\% \\ \text{Process Contingency \%} &= 5\% \\ \text{Project Contingency, C} &= \$ 553,430.87 \\ &= 15\% \text{ of DC + IC} \\ \text{Total Plant Cost, D} &= \$ 4,242,970.02 = \text{DC} + \text{IC} + \text{C} \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \text{Preproduction Costs, G} &= \$ 84,859.40 \\ &= 2\% \text{ of D + E} \\ \text{Inventory Capital, H} &= \$ 2,963.83 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\ \text{Vol}_{\text{reagent}} &= 6188 \text{ gal/yr} \\ \text{Cost}_{\text{reagent}} &= 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \text{Total Capital Investment, TCI} &= \$ 4,330,793.25 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

### Operating and Supervisory Labor:

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

### Maintenance:

$$\text{Maintenance} = 1.5\% \text{ of TCI} \\ \text{Maintenance} = \$ 64,962$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 1028 \text{ hours}$$

### Reagent Consumption:

$$\text{Annual reagent cost} = \text{cost}_{\text{reagent}} \times q_{\text{reagent}} \times t_{\text{op}} \\ \text{Annual reagent cost} = \$ 9,071$$

### Utilities:

$$\text{Power} = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$\text{DP}_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$\text{DP}_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$\text{Power} = 67.6$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 1028 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 4,869$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$R_{\text{layer}} = 1 \quad \text{for full replacement}$$

$$R_{\text{layer}} = 6.2 \quad = n_{\text{layer}} \text{ (for replacing one layer per year)}$$

$$n_{\text{SCR}} = 1 \quad \text{(number of SCR reactors per boiler)}$$

$$\text{Catalyst Replacement Cost} = \$ 329,920.82 \quad \text{(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57)}$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 23$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 1028 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.02$$

$$\text{Annual Catalyst Replacement Cost} = \$ 5,251$$

$$\text{Total DAC} = \$ 4,185,080$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Economic life of SNCR, } n = 20 \quad \text{years}$$

$$\text{CRF} = 0.102$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 4,330,793.25$$

$$\text{IDAC} = \$ 441,101$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 4,626,180.91$$

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #7**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**1028**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**156**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**68**

Reagent sol, gal/hr

**18.4**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

**6188**

Reagent Cost, \$/gallon

**0.48**

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #7**

**NOX Emission Control Option: SCR (80% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 3,074,616	<b>Direct Annual Costs</b>		Efficiency, %	80%
Auxilliary Equipment (Heat Exchanger)	\$ -	Operating & Supervisory Labor	\$38,325	Boiler Heat Input, MMBtu/hr	156
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, and freight. Cost for sales tax and heat exchanger not included.		Maintenance	\$64,962	Total Operating Time, hrs/yr	1028
		Reagent Consumption	\$9,071		
		Utilities	\$4,869		
		Catalyst Replacement	\$5,251	NO <sub>x</sub> removed, tpy	9.6
Total Indirect Capital Costs:		Auxilliary Equipment Requirements	\$69,889		
Indirect Capital, IC	\$ 614,923	gas cost required to heat boiler			
Project Contingency, C	\$ 553,431	exhaust up to SCR required			
		temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 4,242,970				
		Total Direct Annual Costs	\$192,368		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>		\$/ton NO <sub>x</sub> removed	\$ 65,781
Preproduction Costs, G	\$ 84,859				
Inventory Capital, H	\$ 2,964	CRF 0.10185			
Initial Catalyst and Chemicals, I	\$ -	IDAC (CRF x TCI)	\$441,101		
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 4,330,793</b>	<b>TOTAL ANNUAL COST, TAC</b>	<b>\$633,468</b>		

### SCR Design Parameters used for Estimation

Boiler #8 Max. Heat Input,  $Q_B =$  156 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.

	Actual	18.3	MMBtu/hr
	Potential	156	MMBtu/hr
CFBoiler2=	0.12		
	$t_{SCR}$	365	days/yr
$CF_{SCR} =$	1.00		
$CF_{total} =$	0.12		

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)= 0.54 lb/MMBtu (Potential)

$NO_x$  Removal Efficiency,  $\eta_{nox} =$  80%

### Actual Stoichiometric Ratio, ASR

$$ASR = \frac{\text{moles of equivalent } NH_2 \text{ injected}}{\text{mole of uncontrolled } NO_x}$$

The value for ASR in a typical SCR system is approximately = 1.05

### Normalized Stoichiometric Ratio, NSR

$$NSR = ASR \times SR_T$$

(As per pg. 1-24 of SCR manual)

$$SR_T = \frac{1}{\text{(Ratio of equivalent moles of } NH_3 \text{ per mole of reagent injected.)}}$$
$$NSR = 1.05$$

Flue Gas Flow Rate,  $q_{fluegas}$

$q_{fluegas} = 46,600 \text{ acfm - based on testing at boilers.}$

Space Velocity and Area Velocity,  $V_{space}$  &  $V_{area}$  Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$$\begin{aligned} Vol_{reactor} &= 0.02 \text{ ft}^3/\text{cfm} \\ Vol_{reactor} &= 932 \text{ ft}^3 \\ Area_{reactor} &= 0.005 \text{ ft}^2/\text{cfm} \\ Area_{reactor} &= 233 \text{ ft}^2 \\ V_{space} &= \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50 \\ V_{area} &= \frac{V_{space}}{A_{specific}(\text{length}^2/\text{length}^3)} = 200 \end{aligned}$$

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

Catalyst Volume,  $Vol_{catalyst}$  pg 2-36 of SCR manual

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

$Vol_{catalyst} = Vol_{reactor} = 932$

SCR Reactor Dimensions

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

$A_{catalyst} = 48.5 \text{ ft}^2$

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

$$\begin{aligned} A_{SCR} &= 55.8 \text{ ft}^2 \\ l_{scr} &= 7.5 \text{ ft} \\ w_{scr} &= 7.5 \text{ ft} \end{aligned}$$

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

$h'_{layer} =$	3.1	ft (nominal height as per pg. 2-38 of SCR manual)
$n_{layer} =$	6.2	(There must be at least two catalyst layers, pg. 2-38 of SCR manual)

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

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

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

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

(Height of SCR reactor)

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

#### Estimating Reagent Consumption and Tank Size

$$\dot{m}_{reagent} = \frac{NO_{Xin} \times Q_B \times NSR \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X} \times SR_T}$$

$NO_{Xin} =$	0.54	lb/MMBtu
$Q_B =$	156	MMBtu/hr
$NSR =$	1.05	
$\eta_{NO_X} =$	80%	
$M_{reagent} =$	17.03	grams $NH_3$ /mole
$M_{NO_X} =$	46.01	grams $NO_2$ /mole
$SR_T =$	1	(Ratio of equivalent moles of $NH_3$ per mole of reagent injected.)
$\dot{m}_{reagent} =$	26.2	lbs/hr

For ammonia,

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

C <sub>sol</sub> =	19%	(Percent concentration of the aqueous reagent solution)
$\dot{m}_{sol}$ =	137.8	lbs/hr

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

r <sub>sol</sub> =	56	lb/ft <sup>3</sup>	(For aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
v <sub>sol</sub> =	7.481	gal/ft <sup>3</sup>	(Specific volume of aqueous ammonia at 60°F, pg. 2-40 of SCR manual)
q <sub>sol</sub> =	18.4	gph	

Tank volume:

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

t =	14.0	days	(Common on site storage requirement, pg. 2-40 of SCR manual)
Vol <sub>Tank</sub> =	6188	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.

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, and freight. Sales tax is not included. This DC= 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:**

$$DC = Q_B \left[ \frac{\$3,381.6}{MMBtu/hr} + f(h_{SCR}) + f(NH_3 rate) + f(new) + f(bypass) \right] \left( \frac{3500}{Q_B} \right)^{0.35} + f(Vol_{catalyst})$$

Where,

Adjustment for SCR reactor height:

$$f(h_{SCR}) = \left[ \frac{\$5.94}{ft - MMBtu/hr} h_{SCR} \right] - \frac{\$182.4}{MMBtu/hr}$$

$$f(h_{SCR}) = 345$$

Adjustment for the ammonia flow rate:

$$f(NH_3 rate) = \left[ \frac{\$399.0 \dot{m}_{reagent}}{lb/hr - Q_B} \right] - \frac{\$45.9}{MMBtu/hr}$$

$$f(NH_3 rate) = \$ 21.07$$

For a retrofit:

$$f(new) = \$ - \text{ per MMBtu/hr}$$

For a new boiler:

$$f(new) = \$ (706) \text{ per MMBtu/hr}$$

Adjustment for installing an SCR bypass:

$$f(bypass) = \$ - \text{ per MMBtu/hr (if no bypass installed)}$$

$$f(bypass) = \$ 123 \text{ per MMBtu/hr (if bypass installed)}$$

Capital cost for initial catalyst charge:

$$f(Vol_{catalyst}) = Vol_{catalyst} CC_{initial}$$

$$Vol_{catalyst} = \$ 932.00 \text{ ft}^3$$

$$CC_{initial} = \$ 240 \text{ per ft}^3 \text{ (Cost of initial catalyst; current estimation for a ceramic honeycomb catalyst)}$$

$$f(Vol_{catalyst}) = 223680$$

$$\text{Direct Capital, DC} = \$ 3,074,616 \text{ (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2019 was 60)}$$

### 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.

$$\begin{aligned}\text{Total Indirect Installation Costs, IC} &= \$ 614,923 \\&= \text{DC} \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%}) \\&\quad \text{General Facilities \%} = 5\% \\&\quad \text{Engineering and Home Office Fees \%} = 10\% \\&\quad \text{Process Contingency \%} = 5\% \\ \\ \text{Project Contingency, C} &= \$ 553,430.87 \\&\quad = 15\% \text{ of DC + IC} \\ \\ \text{Total Plant Cost, D} &= \$ 4,242,970.02 = \text{DC} + \text{IC} + \text{C} \\ \\ \text{Allowance for Funds During Construction, E} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Royalty Allowance, F} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Preproduction Costs, G} &= \$ 84,859.40 \\&\quad = 2\% \text{ of D + E} \\ \\ \text{Inventory Capital, H} &= \$ 2,963.83 = \text{Vol}_{\text{reagent}}(\text{gal}) \times \text{Cost}_{\text{reagent}}(\$/\text{gal}) \\&\quad \text{Vol}_{\text{reagent}} = 6188 \text{ gal/yr} \\&\quad \text{Cost}_{\text{reagent}} = 0.479 \text{ \$/gal} \quad \text{Vendor quote} \\ \\ \text{Initial Catalyst and Chemicals, I} &= \$ - \text{ (Assumed zero for SCR)} \\ \\ \text{Total Capital Investment, TCI} &= \$ 4,330,793.25 = \text{D} + \text{E} + \text{F} + \text{G} + \text{H} + \text{I}\end{aligned}$$

### 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

$$DAC = \left( \frac{\text{Annual Maintenance}}{\text{Cost}} \right) + \left( \frac{\text{Annual Reagent}}{\text{Cost}} \right) + \left( \frac{\text{Annual Electricity}}{\text{Cost}} \right) + \left( \frac{\text{Annual Water}}{\text{Cost}} \right) + \left( \frac{\text{Annual Catalyst}}{\text{Cost}} \right)$$

#### Operating and Supervisory Labor:

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

#### Maintenance:

$$\text{Maintenance} = 1.5\% \text{ of TCI} \\ \text{Maintenance} = \$ 64,962$$

$$\text{Total operating time, } t_{\text{op}} = CF_{\text{total}} \times 8760 \text{ hrs/yr} = 1028 \text{ hours}$$

#### Reagent Consumption:

$$\text{cost}_{\text{reagent}} = 0.479 \text{ \$/gallon} \\ \text{Annual reagent cost} = \$ 9,071 = q_{\text{reagent}} \times \text{cost}_{\text{reagent}} \times t_{\text{op}}$$

#### Utilities:

$$\text{Power} = 0.105 Q_B [NO_{X_{in}} \eta_{NO_X} + 0.5(\Delta P_{\text{duct}} + n_{\text{total}} \Delta P_{\text{catalyst}})]$$

$$\text{DP}_{\text{duct}} = 2 \text{ inches water (Typical values as per pg. 2-46 of SCR manual)}$$

$$\text{DP}_{\text{catalyst}} = 0.75 \text{ inches water (Typical values as per pg. 2-46 of ScR manual)}$$

$$\text{Power} = 67.6$$

$$\text{Cost}_{\text{elec}} = 0.07 \text{ \$/kwh}$$

$$t_{\text{op}} = 1028 \text{ hours}$$

$$\text{Annual electricity cost} = P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} = \$ 4,869$$

$$\text{Additional Energy Requirement} = \$ 4,100,927 \text{ (Additional heating of exhaust gas required for SCR operations.)}$$

#### Catalyst Replacement:

$$\text{Catalyst Replacement Cost} = n_{\text{SCR}} \times \text{Vol}_{\text{catalyst}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}})$$

$$R_{\text{layer}} = 1 \quad \text{for full replacement}$$

$$R_{\text{layer}} = 6.2 \quad = n_{\text{layer}} \text{ (for replacing one layer per year)}$$

$$n_{\text{SCR}} = 1 \quad \text{(number of SCR reactors per boiler)}$$

$$\text{Catalyst Replacement Cost} = \$ 329,920.82 \quad \text{(Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57)}$$

$$\text{Annual Catalyst Replacement Cost} = (\text{Catalyst Replacement Cost}) \times (\text{FWF})$$

$$\text{Future Worth Factor} = FWF = i \left[ \frac{1}{(1+i)^Y - 1} \right]$$

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Term, } Y = \frac{h_{\text{catalyst}}}{h_{\text{year}}} = 23$$

$$h_{\text{catalyst}} = 24000 \quad \text{hours (operating life of catalyst as per pg. 2-47 of SCR manual)}$$

$$h_{\text{year}} = 1028 \quad \text{hours} = t_{\text{op}}$$

$$\text{FWF} = 0.02$$

$$\text{Annual Catalyst Replacement Cost} = \$ 5,251$$

$$\text{Total DAC} = \$ 4,185,080$$

#### **Indirect Annual Costs, IDAC:**

$$\text{Indirect Annual Cost, IDAC} = \text{CRF} \times \text{TCI}$$

CRF = Capital Recovery Factor,

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

$$\text{Interest rate, } i = 8.00\% \quad \text{US Steel specific rate}$$

$$\text{Economic life of SNCR, } n = 20 \quad \text{years}$$

$$\text{CRF} = 0.102$$

$$\text{TCI} = \text{Total Capital Investment} = \$ 4,330,793.25$$

$$\text{IDAC} = \$ 441,101$$

#### **Total Annual Cost:**

$$\text{Total Annual Cost, TAC} = \text{DAC} + \text{IDAC} = \$ 4,626,180.91$$

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #8**

**NOX Emission Control Option: SCR (80% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh

**0.07**

Interest Rate, %

**8.00%**

Operating Labor, \$/man-hr

**70.00**

Manhours per year

**547.5**

Sales Tax, % of FOB

**N/A**

Freight & Ins. to Site, % of FOB

**Included in DC**

Maintenance (Materials + Labor) % TCI

**1.5%**

**Source Emission Information**

Equipment Life, yr

**20.0**

Operating Hours Per Year

**1028**

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr

**156**

NOX Removal Efficiency,  $\eta_{NOx}$

**80%**

Cost Year

**2019**

Incremental Utility Requirement

Electricity, kw

**68**

Reagent sol, gal/hr

**18.4**

Catalyst operating life, hrs

**24000**

General Facilities, % DC

**5%**

Engineering and Home Office Fees % DC

**10%**

Process Contingency % DC

**5%**

Project Contingency % DC+IC

**15%**

Preproduction Costs % of D+E

**2%**

Reagent Volume, gallons

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Reagent Cost, \$/gallon

**0.48**

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #8**

**NOX Emission Control Option: SCR (80% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 3,074,616	<b>Direct Annual Costs</b>		Efficiency, %	80%
Auxilliary Equipment (Heat Exchanger)	\$ -	Operating & Supervisory Labor	\$38,325	Boiler Heat Input, MMBtu/hr	156
Direct Capital costs includes PEC such as SCR system equipment, instrumentation, and freight. Cost for sales tax and heat exchanger not included.		Maintenance	\$64,962	Total Operating Time, hrs/yr	1028
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Total Plant Cost, D (DC + IC + C)	\$ 4,242,970				
		Total Direct Annual Costs	\$192,368		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>		\$/ton NO <sub>x</sub> removed	\$ 78,888
Preproduction Costs, G	\$ 84,859				
Inventory Capital, H	\$ 2,964	CRF 0.10185			
Initial Catalyst and Chemicals, I	\$ -	IDAC (CRF x TCI)	\$441,101		
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 4,330,793</b>	<b>TOTAL ANNUAL COST, TAC</b>	<b>\$633,468</b>		

**SNCR Costs for Boilers**

<b>Source</b>	<b>Annualized Costs (\$/yr)</b>	<b>Emissions Reduction (tpy)</b>	<b>Cost Effectiveness (\$/ton)</b>
Boiler 1	29,971,810	253.08	118,428
Boiler 2	16,677,946	85.02	196,172
Boiler 5	5,808,765	0.21	27,450,808
Boiler 6	5,808,765	6.23	932,337
Boiler 7	4,464,920	5.42	824,022
Boiler 8	4,464,920	4.52	988,827

### SNCR Design Parameters used for Estimation

Boiler #1 Max. Heat Input,  $Q_B =$  760 MMBtu/hr

System Capacity Factor,  $CF_{total} = CF_{plant} \times CF_{SNCR}$

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

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

$$CF_{Boiler \#1} = \frac{Actual_{2012}, MMBtu / hr}{Potential, MMBtu / hr}$$

Actual <sub>2012</sub>	467.5	MMBtu/hr
Potential	760	MMBtu/hr
CF <sub>boiler1</sub>	0.62	

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

t <sub>SNCR</sub>	365	days/yr
CF <sub>SNCR</sub>	1.00	
CF <sub>total</sub>	0.62	

### Uncontrolled NO<sub>x</sub>, Stack NO<sub>x</sub> and NO<sub>x</sub> Removal Efficiency

NO <sub>x</sub> <sub>in</sub> (uncontrolled)=	0.54	lb/MMBtu (Potential)
NO <sub>x</sub> Removal Efficiency, $\eta_{NOx}$	45%	
Stack NO <sub>x</sub> =	0.297	lb/MMBtu (Estimated)

### Normalized Stoichiometric Ratio, NSR

$$NSR = \frac{\left[ \left( \frac{2molUrea}{molNO_x} \right) \times NO_{x_{in}} + 0.7 \right] \times \eta_{NO_x}}{NO_{x_{in}}}$$

NSR = 1.48



## Estimating Reagent Consumption

Reagent Consumption Parameters:

$\rho_{sol}$ =	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 <sub>2</sub> (grams/mol NO <sub>2</sub> )
$SR_T$ =	2	Ratio of equivalent moles of NH <sub>3</sub> per mole of reagent (mols NH <sub>3</sub> /mol Urea)
$C_{sol}$ =	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$$\dot{m}_{reagent} = 178.8 \text{ lbs/hr}$$

Aqueous reagent solution mass flow rate:

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

$$\dot{m}_{sol} = 357.6 \text{ lbs/hr}$$

Solution volume flow rate:

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

$$q_{sol} = 37.68 \text{ gph}$$

Aqueous reagent solution storage:

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

$$t_{storage} = 14.00 \text{ days (Assumption from pg. 1-27 in SNCR manual)}$$

$$V_{tank} = 12659.11 \text{ gallons}$$

## 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.

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= Indirect Capital

#### Total Direct Capital Costs, DC:

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

DC = \$ 2,142,517.09 (Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57)

#### Indirect Capital Costs:

**Total Indirect Installation Costs, IC = \$ 428,503**

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

General Facilities % = 5%

Engineering and Home Office Fees % = 10%

Process Contingency % = 5%

Project Contingency, C = \$ 385,653.08

= 15% of DC + IC

Total Plant Cost, D = \$ 2,956,673.58 = DC + IC + C

Allowance for Funds During Construction, E = \$ - (Assumed zero for SNCR)

Royalty Allowance, F = \$ - (Assumed zero for SNCR)

Preproduction Costs, G = \$ 59,133.47  
= 2% of D + E

Inventory Capital, H = \$ 608,903.33 = Vol<sub>reagent</sub>(gal) x Cost<sub>reagent</sub>(\$/gal)  
Vol<sub>reagent</sub> = 329137 gal/yr  
Cost<sub>reagent</sub> = 1.85 \$/gal \$/gallon (Mundi Price Index for January 2014, United States)

Initial Catalyst and Chemicals, I = \$ - (Assumed zero for SNCR)

Total Capital Investment, TCI = \$ 3,624,710.39 = D + E + F + G + H + I

#### TOTAL ANNUAL COSTS

TAC = Total Annual Cost

Includes: direct costs, indirect costs, and recovery credits.

DAC =

Direct Annual Costs

Include: variable and semivariable costs.

Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the SNCR.

Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \left( \begin{matrix} \text{Annual} \\ \text{Maintenance} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Reagent} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Electricity} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Water} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Fuel} \\ \text{Cost} \end{matrix} \right)$$

#### Operating and Supervisory Labor:

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

#### Maintenance:

1.5% of TCI  
Maintenance = \$ 54,371

Total operating time, t<sub>op</sub> = CF<sub>total</sub> x 8760 hrs/yr 8760 hours (CF not used as max hours required for RACT analysis)

#### Reagent Consumption (Urea):

$$\text{Annual reagent cost} = \text{cost}_{\text{reagent}} \times \text{q}_{\text{sol}} \times \text{cost}_{\text{reagent}} \times \text{t}_{\text{op}}$$

cost<sub>reagent</sub> = 1.85 \$/gallon (Mundi Price Index for January 2014, United States)

Annual reagent cost = \$ 610,576

#### Utilities:

Power Consumption, P:

$$P = \frac{0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_B}{9.5}$$

NOx<sub>in</sub> (uncontrolled) = 0.54 lb/MMBtu

NSR (Normalized Stoichiometric Ratio): 1.48333333

Q<sub>B</sub>, boiler heat input = 760 MMBtu/hr

P = 30 kw

Cost<sub>elec</sub> = 0.07 \$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.go

t<sub>op</sub> = 8760 hours

Annual electricity cost = P x Cost<sub>elec</sub> x t<sub>op</sub> = \$ 18,468 per kWh

#### Water Consumption:

$$q_{\text{water}} = \frac{\dot{m}_{\text{sol}}}{\rho_{\text{water}}} \left( \frac{C_{\text{UreaSol}_{\text{feed}}}}{C_{\text{UreaSol}_{\text{out}}}} - 1 \right)$$

For urea dilution from a 50% solution to a 10% solution q<sub>water</sub> becomes:

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

ρ<sub>water</sub> = 8.345 lb/gal

q<sub>water</sub> = 0.17141 1,000 gallons/hour

Annual water cost = q<sub>water</sub> x Cost<sub>water</sub> x t<sub>op</sub> =

Cost<sub>water</sub> = 8.37 \$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial Use)

\$ 12,567.67 <http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.shtml>

Additional Fuel Consumption:

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

Assumptions:

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

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

$$\Delta F_{uel} \left( \frac{MMBtu}{hr} \right) = 1.4483$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Coke oven gas	409.5	MMBtu/hr
Natural gas	58.00	MMBtu/hr
Total MMBtu/hr	467.50	

Percent usage:

Coke oven gas	0.88
Natural gas	0.12

Additional fuel required:

Natural gas	1.44826	MMBtu/hr
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Total cost associated with additional fuel usage:

Natural gas cost	9.44	\$/MMBtu
\$	119,763.05	\$/yr

Total Natural gas: \$ 119,763.05

Additional Energy Requirement = \$ 28,748,554 (Additional heating of exhaust gas required for SNCR operations.)

Total DAC = \$ 29,564,299.75

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

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

Interest rate, i =	8.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n=	20	years
CRF =	0.10	

TCI = Total Capital Investment = \$ 3,624,710.39

IDAC = \$ 369,184.76

**Total Annual Cost:**

Total Annual Cost, TAC = DAC + IDAC = \$ 29,933,484.51

**COMPANY: United State Steel**  
**LOCATION: Clairton**  
**Source: Boiler #1**  
**NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh	0.07
Interest Rate, %	8.00%
Water, \$/1,000 gal	8.37
NG, \$/MMBtu	9.44

Operating Labor, \$/man-hr	70.00
Manhours per year	547.5
Sales Tax, % of FOB	Included in DC
Freight & Ins. to Site, % of FOB	Included in DC
Maintenance (Materials + Labor) % TCI	1.5%
General Facilities, % DC	5%
Engineering and Home Office Fees % DC	10%
Process Contingency % DC	5%
Project Contingency % DC+IC	15%
Preproduction Costs % of D+E	2%

**Source Emission Information**

Equipment Life, yr	20.0
Operating Hours Per Year	8760

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr	760
NOX Removal Efficiency, $\eta_{NOx}$	45%
Cost Year	2019

Incremental Utility Requirements

Electricity, kw	30
Reagent sol, gal/hr	37.68
Water, 1,000 gal/hr	0.17
NG, MMBtu/hr	1.44826

Reagent Volume, gallons	329137
Reagent Cost, \$/gallon	1.85

E

**COMPANY: United State Steel**

**LOCATION: Clairton**

**Source: Boiler #1**

**NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 2,142,517	<b>Direct Annual Costs</b>		NO <sub>x</sub> <sub>in</sub> , lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger, \$	-	Operating & Supervisory Labor	\$38,325	Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.		Maintenance	\$54,371	Boiler Heat Input, MMBtu/hr	760
		Reagent Consumption	\$610,576	Total Operating Time, hrs/yr	8760
		Utilities	\$18,468		
		Water Consumption	\$12,568	NO <sub>x</sub> removed, tpy	253.1
Total Indirect Capital Costs:		Add'l Fuel Usage (Process related)	\$119,763.05		
Indirect Installation, IC	\$ 428,503	Auxilliary Equipment Requirements	\$ 28,748,554		
Project Contingency, C	\$ 385,653	(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 2,956,674				
		Total Direct Annual Costs	\$29,602,625	<b>Cost Efficiency:</b>	
Allowance for Funds During Constr., E	\$ -			<b>\$/ton NO<sub>x</sub> removed</b>	<b>\$118,428</b>
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>			
Preproduction Costs, G	\$ 59,133	CRF	0.102		
Inventory Capital, H	\$ 608,903	Total IDAC (CRF x TCI)	\$ 369,185		
Initial Catalyst and Chemicals, I	\$ -				
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 3,624,710</b>	<b>TOTAL ANNUAL COST, TAC (DAC + IDAC)</b>	<b>\$ 29,971,810</b>		



### SNCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input,  $Q_B =$  481 MMBtu/hr

System Capacity Factor,  $CF_{total} = CF_{plant} \times CF_{SNCR}$

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

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

$$CF_{Boiler\#2} = \frac{Actual_{2012}, MMBtu/hr}{Potential, MMBtu/hr}$$

Actual <sub>2012</sub>	216	MMBtu/hr
Potential	481	MMBtu/hr
CFBoiler2=	0.45	

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

t <sub>SNCR</sub>	365	days/yr
CF <sub>SNCR</sub> =	1.00	
CF <sub>total</sub> =	0.45	

### Uncontrolled NO<sub>x</sub>, Stack NO<sub>x</sub> and NO<sub>x</sub> Removal Efficiency

NO <sub>x,in</sub> , (uncontrolled)=	0.54	lb/MMBtu (Potential)
NO <sub>x</sub> Removal Efficiency, $\eta_{NOx}$	45%	
Stack NO <sub>x</sub> =	0.297	lb/MMBtu (Estimated)

### Normalized Stoichiometric Ratio, NSR

$$NSR = \frac{\left[ \left( \frac{2molUrea}{molNO_x} \right) \times NO_{x,in} + 0.7 \right] \times \eta_{NOx}}{NO_{x,in}}$$

NSR = 1.48

## 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 <sub>2</sub> (grams/mol NO <sub>2</sub> )
$SR_T$ =	2	Ratio of equivalent moles of NH <sub>3</sub> per mole of reagent (mols NH <sub>3</sub> /mol Urea)
$C_{sol}$ =	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$$\dot{m}_{reagent} = 113.2 \text{ lbs/hr}$$

Aqueous reagent solution mass flow rate:

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

$$\dot{m}_{sol} = 226.3 \text{ lbs/hr}$$

Solution volume flow rate:

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

$$q_{sol} = 23.84 \text{ gph}$$

Aqueous reagent solution storage:

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

$$t_{storage} = 14.00 \text{ days (Assumption from pg. 1-27 in SNCR manual)}$$

$$V_{tank} = 8011.89 \text{ gallons}$$

## TOTAL CAPITAL INVESTMENT, TCI

$$\text{Cost Year} = 2014$$

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 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:

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

$$DC = \$ 1,765,580.45 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57})$$

#### Indirect Capital Costs:

$$\text{Total Indirect Installation Costs, IC} = \$ 353,116$$

$$= DC \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%})$$

$$\text{General Facilities \%} = 5\%$$

$$\text{Engineering and Home Office Fees \%} = 10\%$$

$$\text{Process Contingency \%} = 5\%$$

$$\text{Project Contingency, C} = \$ 317,804.48$$

$$= 15\% \text{ of } DC + IC$$

$$\text{Total Plant Cost, D} = \$ 2,436,501.03 = DC + IC + C$$

Allowance for Funds During Construction, E = \$ - (Assumed zero for SNCR)

Royalty Allowance, F = \$ - (Assumed zero for SNCR)

Preproduction Costs, G = \$ 48,730.02  
= 2% of D + E

Inventory Capital, H = \$ 385,371.71 = Vol<sub>reagent</sub>(gal) x Cost<sub>reagent</sub>(\$/gal)  
Vol<sub>reagent</sub> = 208309 gal/yr  
Cost<sub>reagent</sub> = 1.85 \$/gal \$/gallon (Mundi Price Index for January 2014, United States)

Initial Catalyst and Chemicals, I = \$ - (Assumed zero for SNCR)

Total Capital Investment, TCI = \$ 2,870,602.76 = D + E + F + G + H + I

#### TOTAL ANNUAL COSTS

TAC = Total Annual Cost

Includes: direct costs, indirect costs, and recovery credits.

DAC =

Direct Annual Costs

Include: variable and semivariable costs.

Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the SNCR.

Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \left( \begin{matrix} \text{Annual} \\ \text{Maintenance} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Reagent} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Electricity} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Water} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Fuel} \\ \text{Cost} \end{matrix} \right)$$

#### Operating and Supervisory Labor:

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

#### Maintenance:

1.5% of TCI  
Maintenance = \$ 43,059

Total operating time, t<sub>op</sub> = CF<sub>total</sub> x 8760 hrs/yr 8760 hours (CF not used as max hours required for RACT analysis)

#### Reagent Consumption (Urea):

$$\text{Annual reagent cost} = \text{cost}_{\text{reagent}} \times \text{q}_{\text{sol}} \times \text{cost}_{\text{reagent}} \times \text{t}_{\text{op}}$$

cost<sub>reagent</sub> = 1.85 \$/gallon (Mundi Price Index for January 2014, United States)

Annual reagent cost = \$ 386,430

#### Utilities:

Power Consumption, P:

$$P = \frac{0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_B}{9.5}$$

NOx<sub>in</sub> (uncontrolled) = 0.54 lb/MMBtu

NSR (Normalized Stoichiometric Ratio): 1.48333333

Q<sub>B</sub>, boiler heat input = 481 MMBtu/hr

P = 19 kw

Cost<sub>elec</sub> = 0.07 \$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.go

t<sub>op</sub> = 8760 hours

Annual electricity cost = P x Cost<sub>elec</sub> x t<sub>op</sub> = \$ 11,688 per kWh

#### Water Consumption:

$$q_{\text{water}} = \frac{\dot{m}_{\text{sol}}}{\rho_{\text{water}}} \left( \frac{C_{\text{UreaSol}_{\text{feed}}}}{C_{\text{UreaSol}_{\text{out}}}} - 1 \right)$$

For urea dilution from a 50% solution to a 10% solution q<sub>water</sub> becomes:

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

ρ<sub>water</sub> = 8.345 lb/gal

q<sub>water</sub> = 0.10848 1,000 gallons/hour

Annual water cost = q<sub>water</sub> x Cost<sub>water</sub> x t<sub>op</sub> =

Cost<sub>water</sub> = 8.37 \$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial Use)

\$ 7,954.02 <http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.shtml>

#### Additional Fuel Consumption:

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

Assumptions:

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

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

$$\Delta F_{fuel} \left( \frac{MMBtu}{hr} \right) = 0.9166$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Coke oven gas	189.6	MMBtu/hr
Natural gas	26.40	MMBtu/hr
Total MMBtu/hr	216.00	

Percent usage:

Coke oven gas	0.88
Natural gas	0.12

Additional fuel required:

Natural gas	0.91660	MMBtu/hr
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Total cost associated with additional fuel usage:

Natural gas cost	9.44	\$/MMBtu
\$	75,797.40	\$/yr

Total Natural gas:	\$	75,797.40
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Additional Energy Requirement =	\$	15,822,314	(Additional heating of exhaust gas required for SNCR operations.)
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Total DAC =	\$	16,347,243.57
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Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

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

Interest rate, i =	8.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n =	20	years
CRF =	0.10	

TCI = Total Capital Investment =	\$	2,870,602.76
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IDAC =	\$	292,377.23
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**Total Annual Cost:**

Total Annual Cost, TAC = DAC + IDAC =	\$	16,639,620.80
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**COMPANY: United State Steel**  
**LOCATION: Clairton**  
**Source: Boiler #2**  
**NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh	0.07
Interest Rate, %	8.00%
Water, \$/1,000 gal	8.37
NG, \$/MMBtu	9.44

Operating Labor, \$/man-hr	70.00
Manhours per year	547.5
Sales Tax, % of FOB	Included in DC
Freight & Ins. to Site, % of FOB	Included in DC
Maintenance (Materials + Labor) % TCI	1.5%
General Facilities, % DC	5%
Engineering and Home Office Fees % DC	10%
Process Contingency % DC	5%
Project Contingency % DC+IC	15%
Preproduction Costs % of D+E	2%

**Source Emission Information**

Equipment Life, yr	20.0
Operating Hours Per Year	8760

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr	481
NOX Removal Efficiency, $\eta_{NOx}$	45%
Cost Year	2019

Incremental Utility Requirements

Electricity, kw	19
Reagent sol, gal/hr	23.84
Water, 1,000 gal/hr	0.11
NG, MMBtu/hr	0.91660

Reagent Volume, gallons	208309
Reagent Cost, \$/gallon	1.85

E



### NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 1,765,580	<b>Direct Annual Costs</b>		NO <sub>x</sub> <sub>m</sub> , lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger, \$	-	Operating & Supervisory Labor	\$38,325	Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.		Maintenance	\$43,059	Boiler Heat Input, MMBtu/hr	481
		Reagent Consumption	\$386,430	Total Operating Time, hrs/yr	8760
		Utilities	\$11,688		
		Water Consumption	\$7,954	NO <sub>x</sub> removed, tpy	85.0
Total Indirect Capital Costs:		Add'l Fuel Usage (Process related)	\$75,797.40		
Indirect Capital, IC	\$ 353,116	Auxilliary Equipment Requirements	\$ 15,822,314		
Project Contingency, C	\$ 317,804	(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 2,436,501				
		Total Direct Annual Costs	\$16,385,569	<b>Cost Efficiency:</b>	
Allowance for Funds During Constr., E	\$ -			\$/ton NO <sub>x</sub> removed	\$196,172
Royalty Allowance,F	\$ -	<b>Indirect Annual Costs</b>			
Preproduction Costs, G	\$ 48,730				
Inventory Capital, H	\$ 385,372	CRF	0.102		
Initial Catalyst and Chemicals, I	\$ -	Total IDAC (CRF x TCI)	\$ 292,377		
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 2,870,603</b>	<b>TOTAL ANNUAL COST, TAC (DAC + IDAC)</b>	<b>\$ 16,677,946</b>		

### SNCR Design Parameters used for Estimation

Boiler # R1/R2 Max. Heat Input,  $Q_B =$  229 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.

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

$$CF_{R1R2} = \frac{Actual_{2012}, MMBtu / hr}{Potential, MMBtu / hr}$$

Actual <sub>2012</sub>	13.44	MMBtu/hr
Potential	229	MMBtu/hr
$CF_{R1R2} =$	0.06	

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

$t_{SNCR}$	365	days/yr
$CF_{SNCR} =$	1.00	
$CF_{total} =$	0.06	

### Uncontrolled $NO_x$ , Stack $NO_x$ and $NO_x$ Removal Efficiency

$NO_{x_{in}}$ , (uncontrolled)=	0.54	lb/MMBtu (Potential)
NOX Removal Efficiency, $\eta_{NOx}$	45%	
Stack $NO_x =$	0.297	lb/MMBtu (Estimated)

### Normalized Stoichiometric Ratio, NSR

$$NSR = \frac{\left[ \left( \frac{2molUrea}{molNO_x} \right) \times NO_{x_{in}} + 0.7 \right] \times \eta_{NO_x}}{NO_{x_{in}}}$$

NSR = 1.48

## Estimating Reagent Consumption

Reagent Consumption Parameters:

$\rho_{sol}$	=	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 <sub>2</sub> (grams/mol NO <sub>2</sub> )
$SR_T$	=	2	Ratio of equivalent moles of NH <sub>3</sub> per mole of reagent (mols NH <sub>3</sub> /mol Urea)
$C_{sol}$	=	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{x_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$$\dot{m}_{reagent} = 53.9 \text{ lbs/hr}$$

Aqueous reagent solution mass flow rate:

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

$$\dot{m}_{sol} = 107.7 \text{ lbs/hr}$$

Solution volume flow rate:

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

$$q_{sol} = 11.35 \text{ gph}$$

Aqueous reagent solution storage:

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

$$t_{storage} = 14.00 \text{ days (Assumption from pg. 1-27 in SNCR manual)}$$

$$V_{tank} = 3814.39 \text{ gallons}$$

## 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.

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= Indirect Capital

### Total Direct Capital Costs, DC:

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

DC = \$ 1,289,883.70 (Chemical Engineering Plant Index difference applied to DC; CEPICI in 1998 was 389.5; CEPICI in 2013 was 574.5)

### Indirect Capital Costs:

**Total Indirect Installation Costs, IC = \$ 257,977**

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

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

Project Contingency, C = \$ 232,179.07  
= 15% of DC + IC

Total Plant Cost, D = \$ 1,780,039.50 = DC + IC + C

Allowance for Funds During Construction, E = \$ - (Assumed zero for SNCR)

Royalty Allowance, F = \$ - (Assumed zero for SNCR)

Preproduction Costs, G = \$ 35,600.79  
= 2% of D + E

Inventory Capital, H = \$ 183,472.19 = Vol<sub>reagent</sub>(gal) x Cost<sub>reagent</sub>(\$/gal)  
Vol<sub>reagent</sub> = 99174 gal/yr  
Cost<sub>reagent</sub> = 1.85 \$/gal \$/gallon (Mundi Price Index for January 2014, United States)

Initial Catalyst and Chemicals, I = \$ - (Assumed zero for SNCR)

Total Capital Investment, TCI = \$ 1,999,112.48 = D + E + F + G + H + I

TOTAL ANNUAL COSTS

DAC =

TAC = Total Annual Cost  
Includes: direct costs, indirect costs, and recovery credits.  
Direct Annual Costs  
Include: variable and semivariable costs.  
Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the SNCR.  
Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \left( \begin{matrix} \textit{Annual} \\ \textit{Maintenance} \\ \textit{Cost} \end{matrix} \right) + \left( \begin{matrix} \textit{Annual} \\ \textit{Reagent} \\ \textit{Cost} \end{matrix} \right) + \left( \begin{matrix} \textit{Annual} \\ \textit{Electricity} \\ \textit{Cost} \end{matrix} \right) + \left( \begin{matrix} \textit{Annual} \\ \textit{Water} \\ \textit{Cost} \end{matrix} \right) + \left( \begin{matrix} \textit{Annual} \\ \textit{Fuel} \\ \textit{Cost} \end{matrix} \right)$$

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

Maintenance:

1.5% of TCI  
Maintenance = \$ 29,987

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

Reagent Consumption (Urea):

$cost_{reagent}$       1.85      \$/gallon (As per page i-39 from SNCR manual; CPI ratio applied to reflect 2014 prices)  
Annual reagent cost = \$      183,976      =  $q_{sol} \times cost_{reagent} \times t_{op}$

#### Utilities:

Power Consumption, P:

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

NOx <sub>in</sub> (uncontrolled)=	0.54	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):	1.48	
Q <sub>B</sub> , boiler heat input=	229	MMBtu/hr
P =	9	kw
Cost <sub>elec</sub> =	0.07	\$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)
t <sub>op</sub> =	8760	hours
Annual electricity cost = P x Cost <sub>elec</sub> x t <sub>op</sub> =	\$ 5,565	per kWh

#### Water Consumption:

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

For urea dilution from a 50% solution to a 10% solution q<sub>water</sub> becomes:

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

ρ <sub>water</sub> =	8.345	lb/gal
q <sub>water</sub> =	0.05165	1,000 gallons/hour
Annual water cost = q <sub>water</sub> x Cost <sub>water</sub> x t <sub>op</sub> =		
Cost <sub>water</sub> =	8.37	\$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial Users)
\$	3,786.84	

Additional Fuel Consumption:

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

Assumptions:

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

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

$$\Delta F_{uel} \left( \frac{MMBtu}{hr} \right) = 0.4364$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Natural gas	0.00	MMBtu/hr
Coke oven gas	13.44	MMBtu/hr
Total MMBtu/hr	13.44	

Percent usage:

Natural gas	0.00
Coke oven gas	1.00

Additional fuel required:

Natural gas	0.43638	MMBtu/hr
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Total cost associated with additional fuel usage:

Natural gas cost	9.44	\$/MMBtu
\$	36,086.50	\$/yr

Total Natural gas: \$ 36,086.50

Additional Energy Requirement = \$ 5,307,425 (Additional heating of exhaust gas required for SNCR operations.)

Total DAC = \$ 5,566,826.36

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

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

Interest rate, i =	8.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n =	20	years
CRF =	0.10	

TCI = Total Capital Investment = \$ 1,999,112.48

IDAC = \$ 203,614.02

**Total Annual Cost:**

Total Annual Cost, TAC = DAC + IDAC = \$ 5,770,440.39



**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #s R1/R2**

**NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh	0.07
Interest Rate, %	8.00%
Water, \$/1,000 gal	8.37
NG, \$/MMBtu	9.44

Operating Labor, \$/man-hr	70.00
Manhours per year	547.5
Sales Tax, % of FOB	Included in DC
Freight & Ins. to Site, % of FOB	Included in DC
Maintenance (Materials + Labor) % TCI	1.5%
General Facilities, % DC	5%
Engineering and Home Office Fees % DC	10%
Process Contingency % DC	5%
Project Contingency % DC+IC	15%
Preproduction Costs % of D+E	2%

**Source Emission Information**

Equipment Life, yr	20.0
Operating Hours Per Year	8760

**Control Technology Information**

Furnace Fuel Rating, mmBTU/hr	229
NOX Removal Efficiency, $\eta_{NOx}$	45%
Cost Year	2019

Incremental Utility Requirements

Electricity, kw	9
Reagent sol, gal/hr	11.35
Water, 1,000 gal/hr	0.05
NG, MMBtu/hr	0.44

Reagent Volume, gallons	99174
Reagent Cost, \$/gallon	1.85

### NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 1,289,884	<b>Direct Annual Costs</b>		NO <sub>x</sub> , lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger	\$ -	Operating & Supervisory Labor	\$38,325	Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.		Maintenance	\$29,987	Heater Heat Input, MMBtu/hr	229
		Reagent Consumption	\$183,976	Total Operating Time, hrs/yr	8760
		Utilities	\$5,565		
		Water Consumption	\$3,787	NO <sub>x</sub> removed, tpy	0.2
Total Indirect Capital Costs:		Add'l Fuel Usage (Process related)	\$36,086.50		
Indirect Capital, IC	\$ 257,977	Auxilliary Equipment Requirements	\$ 5,307,425		
Project Contingency, C	\$ 232,179	(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 1,780,040				
		Total Direct Annual Costs	\$5,605,151	<b>Cost Efficiency:</b>	
Allowance for Funds During Constr., E	\$ -			\$/ton NO <sub>x</sub> removed	\$27,450,808
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>			
Preproduction Costs, G	\$ 35,601	CRF	0.102		
Inventory Capital, H	\$ 183,472	Total IDAC (CRF x TCI)	\$ 203,614		
Initial Catalyst and Chemicals, I	\$ -				
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 1,999,112</b>	<b>TOTAL ANNUAL COST, TAC (DAC + IDAC)</b>	<b>\$ 5,808,765</b>		

### SNCR Design Parameters used for Estimation

Boiler T1/T2 Max. Heat Input,  $Q_B =$  156 MMBtu/hr

System Capacity Factor,  $CF_{total} = CF_{plant} \times CF_{SNCR}$

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

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

$$CF_{T1/T2} = \frac{Actual_{2012}, MMBtu / hr}{Potential, MMBtu / hr}$$

$$CF_{T1/T2} = 0.12$$

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

Actual<sub>2012</sub> 18.56 MMBtu/hr  
Potential 156 MMBtu/hr

$t_{SNCR}$  365 days/yr

$$CF_{SNCR} = 1.00$$

$$CF_{total} = 0.12$$

### Uncontrolled NO<sub>x</sub>, Stack NO<sub>x</sub> and NO<sub>x</sub> Removal Efficiency

NO<sub>x</sub><sub>in</sub>, (uncontrolled)= 0.54 lb/MMBtu (Potential)

NO<sub>x</sub> Removal Efficiency,  $\eta_{NOx}$  45%

Stack NO<sub>x</sub> = 0.297 lb/MMBtu (Estimated)

### Normalized Stoichiometric Ratio, NSR

$$NSR = \frac{\left[ \left( \frac{2molUrea}{molNO_x} \right) \times NO_{x_{in}} + 0.7 \right] \times \eta_{NO_x}}{NO_{x_{in}}}$$

$$NSR = 1.48$$

### Estimating Reagent Consumption

Reagent Consumption Parameters:

$\rho_{sol}$ =	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 <sub>2</sub> (grams/mol NO <sub>2</sub> )
$SR_T$ =	2	Ratio of equivalent moles of NH <sub>3</sub> per mole of reagent (mols NH <sub>3</sub> /mol Urea)
$C_{sol}$ =	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (assumption as per page 1-27 of SNCR manual)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$

$$\dot{m}_{reagent} = 36.7 \text{ lbs/hr}$$

Aqueous reagent solution mass flow rate:

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

$$\dot{m}_{sol} = 73.4 \text{ lbs/hr}$$

Solution volume flow rate:

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

$$q_{sol} = 7.73 \text{ gph}$$

Aqueous reagent solution storage:

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

$$t_{storage} = 14.00 \text{ days (Assumption from pg. 1-27 in SNCR manual)}$$

$$V_{tank} = 2598.45 \text{ gallons}$$

### TOTAL CAPITAL INVESTMENT, TCI

$$\text{Cost Year} = 2014$$

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 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:

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

$$DC = \$ 1,096,558.61 \quad (\text{Chemical Engineering Plant Index difference applied to DC; CEPCI in 1998 was 389.5; CEPCI in 2013 was 57})$$

#### Indirect Capital Costs:

$$\text{Total Indirect Installation Costs, IC} = \$ 219,312$$

$$= DC \times (\text{General Facilities \%} + \text{Engineering and Home Office Fees \%} + \text{Process Contingency \%})$$

$$\text{General Facilities \%} = 5\%$$

$$\text{Engineering and Home Office Fees \%} = 10\%$$

$$\text{Process Contingency \%} = 5\%$$

$$\text{Project Contingency, C} = \$ 197,380.55$$

$$= 15\% \text{ of } DC + IC$$

$$\text{Total Plant Cost, D} = \$ 1,513,250.89 = DC + IC + C$$

Allowance for Funds During Construction, E = \$ - (Assumed zero for SNCR)

Royalty Allowance, F = \$ - (Assumed zero for SNCR)

Preproduction Costs, G = \$ 30,265.02  
= 2% of D + E

Inventory Capital, H = \$ 124,985.42 = Vol<sub>reagent</sub>(gal) x Cost<sub>reagent</sub>(\$/gal)  
Vol<sub>reagent</sub> = 67560 gal/yr  
Cost<sub>reagent</sub> = 1.85 \$/gal \$/gallon (Mundi Price Index for January 2014, United States)

Initial Catalyst and Chemicals, I = \$ - (Assumed zero for SNCR)

Total Capital Investment, TCI = \$ 1,668,501.32 = D + E + F + G + H + I

#### TOTAL ANNUAL COSTS

TAC = Total Annual Cost

Includes: direct costs, indirect costs, and recovery credits.

DAC =

Direct Annual Costs

Include: variable and semivariable costs.

Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the SNCR.

Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \left( \begin{matrix} \text{Annual} \\ \text{Maintenance} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Reagent} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Electricity} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Water} \\ \text{Cost} \end{matrix} \right) + \left( \begin{matrix} \text{Annual} \\ \text{Fuel} \\ \text{Cost} \end{matrix} \right)$$

#### Operating and Supervisory Labor:

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

#### Maintenance:

1.5% of TCI  
Maintenance = \$ 25,028

Total operating time, t<sub>op</sub> = CF<sub>total</sub> x 8760 hrs/yr 8760 hours (CF not used as max hours required for RACT analysis)

#### Reagent Consumption (Urea):

$$\text{Annual reagent cost} = \text{cost}_{\text{reagent}} \times \text{q}_{\text{sol}} \times \text{t}_{\text{op}}$$

cost<sub>reagent</sub> = 1.85 \$/gallon (Mundi Price Index for January 2014, United States)  
 Annual reagent cost = \$ 125,329

#### Utilities:

Power Consumption, P:

$$P = \frac{0.47 \times \text{NOx}_m \times \text{NSR} \times Q_B}{9.5}$$

NOx<sub>m</sub> (uncontrolled) = 0.54 lb/MMBtu  
 NSR (Normalized Stoichiometric Ratio): 1.48333333  
 Q<sub>B</sub>, boiler heat input = 156 MMBtu/hr  
 P = 6 kw  
 Cost<sub>elec</sub> = 0.07 \$/kwh (average 2014 cost, from US Energy Information Administration statistics for Pennsylvania, www.bls.gov)  
 t<sub>op</sub> = 8760 hours  
 Annual electricity cost = P x Cost<sub>elec</sub> x t<sub>op</sub> = \$ 3,791 per kWh

#### Water Consumption:

$$q_{\text{water}} = \frac{\dot{m}_{\text{sol}}}{\rho_{\text{water}}} \left( \frac{C_{\text{UreaSol}_{\text{feed}}}}{C_{\text{UreaSol}_{\text{dil}}}} - 1 \right)$$

For urea dilution from a 50% solution to a 10% solution q<sub>water</sub> becomes:

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

ρ<sub>water</sub> = 8.345 lb/gal  
 q<sub>water</sub> = 0.03518 1,000 gallons/hour

Annual water cost = q<sub>water</sub> x Cost<sub>water</sub> x t<sub>op</sub> =  
 Cost<sub>water</sub> = 8.37 \$/1,000 gallons (2014 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for Industrial Users)  
 \$ 2,579.68 <http://www.earthtimes.org/articles/show/average-us-water-costs-increase-by-73,554302.shtml>

Additional Fuel Consumption:

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

Assumptions:

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

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

$$\Delta F_{uel} \left( \frac{MMBtu}{hr} \right) = 0.2973$$

Annual cost for additional fuel:

Average annual fuel consumption (calculated from 2012 fuel use data):

Coke oven gas	18.56	MMBtu/hr
Natural gas	0	MMBtu/hr
Total MMBtu/hr	18.56	

Percent usage:

Coke oven gas	1.00
Natural gas	0.00

Additional fuel required:

Natural gas	0.29727	MMBtu/hr
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Total cost associated with additional fuel usage:

Natural gas cost	9.44	\$/MMBtu
\$	24,582.94	\$/yr
Total Natural gas:	\$	24,582.94
Additional Energy Requirement =	\$	4,075,344 (Additional heating of exhaust gas required for SNCR operations.)
Total DAC =	\$	4,256,654.24

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI

CRF = Capital Recovery Factor,

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

Interest rate, i =	8.00%	(US Steel Specific Interest Rate)
Economic life of SNCR, n =	20	years
CRF =	0.10	

TCI = Total Capital Investment = \$ 1,668,501.32

IDAC = \$ 169,940.55

**Total Annual Cost:**

Total Annual Cost, TAC = DAC + IDAC = \$ 4,426,594.78

**COMPANY: United States Steel**  
**LOCATION: Clairton**  
**Source: Boiler #s T1/T2**  
**NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)**

**Site Information**

Utility Unit Costs

Electricity, \$/kwh	0.07
Interest Rate, %	8.00%
Water, \$/1,000 gal	8.37
NG, \$/MMBtu	9.44

Operating Labor, \$/man-hr	70.00
Manhours per year	547.5
Sales Tax, % of FOB	Included in DC
Freight & Ins. to Site, % of FOB	Included in DC
Maintenance (Materials + Labor) % TCI	1.5%
General Facilities, % DC	5%
Engineering and Home Office Fees % DC	10%
Process Contingency % DC	5%
Project Contingency % DC+IC	15%
Preproduction Costs % of D+E	2%

**Source Emission Information**

Equipment Life, yr	20.0
Operating Hours Per Year	8760

**Control Technology Information**

Boiler Fuel Rating, mmBTU/hr	156
NOX Removal Efficiency, $\eta_{NOx}$	45%
Cost Year	2019

Incremental Utility Requirements

Electricity, kw	6
Reagent sol, gal/hr	7.73
Water, 1,000 gal/hr	0.04
NG, MMBtu/hr	0.91660

Reagent Volume, gallons	67560
Reagent Cost, \$/gallon	1.85

E

**COMPANY: United States Steel**

**LOCATION: Clairton**

**Source: Boiler #s T1/T2**

**NO<sub>x</sub> Emission Control Option: SNCR (45% Efficiency)**

TOTAL CAPITAL INVESTMENT		TOTAL ANNUAL COST		COST EFFECTIVENESS	
Total Direct Capital Cost, DC	\$ 1,096,559	<b>Direct Annual Costs</b>		NO <sub>x</sub> <sub>in</sub> , lbs/MMBtu	0.54
Auxilliary Equipment (Heat Exchanger), \$	-	Operating & Supervisory Labor	\$38,325	Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.		Maintenance	\$25,028	Boiler Heat Input, MMBtu/hr	156
		Reagent Consumption	\$125,329	Total Operating Time, hrs/yr	8760
		Utilities	\$3,791		
		Water Consumption	\$2,580	NO <sub>x</sub> removed, tpy	5
Total Indirect Capital Costs:		Add'l Fuel Usage (Process related)	\$24,583		
Indirect Capital, IC	\$ 219,312	Auxilliary Equipment Requirements	\$ 4,075,344		
Project Contingency, C	\$ 197,381	(Auxillary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Plant Cost, D (DC + IC + C)	\$ 1,513,251				
		Total Direct Annual Costs	\$4,294,979		
Allowance for Funds During Constr., E	\$ -			<b>Cost Efficiency:</b>	
Royalty Allowance, F	\$ -	<b>Indirect Annual Costs</b>		\$/ton NO <sub>x</sub> removed	\$824,022
Preproduction Costs, G	\$ 30,265	CRF	0.102		
Inventory Capital, H	\$ 124,985	Total IDAC (CRF x TCI)	\$ 169,941		
Initial Catalyst and Chemicals, I	\$ -				
<b>TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)</b>	<b>\$ 1,668,501</b>	<b>TOTAL ANNUAL COST, TAC (DAC + IDAC)</b>	<b>\$ 4,464,920</b>		

lbs NOX/MMcf Natural Gas: 140

# Heat Capacity Boiler Combustion Stack Gas

	BOILER #1		BOILER #2		BOILER # R1/R2		BOILER # T1/T2	
	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)	Flue Gas Composition	Heat Capacity (Btu/ft <sup>3</sup> /°F)
H2O	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225
O2	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185
CO2	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260
N2	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185
<b>Total</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>	<b>100.0%</b>	<b>0.0191</b>

	BOILER #1	BOILER #2	BOILER # R1/R2	BOILER # T1/T2
Flow (1)	182,000 scfm	101,000 scfm	33,600 scfm	25,800 scfm
Flow	1.09E+07 scfh	6.06E+06 scfh	2.02E+06 scfh	1.55E+06 scfh
Temperature <sub>SNCR in</sub> (1)	316 F	327 F	316 F	316 F
Temperature <sub>SNCR out</sub> (2)	1650 F	1650 F	1650 F	1650 F
ΔT	1334 F	1323 F	1334 F	1334 F
Heat Requirement	25.5 Btu/scf	25.3 Btu/scf	25.5 Btu/scf	25.5 Btu/scf
Uncontrolled NOX (1), (3)	12718.6 ppmv	8049.5 ppmv	3832.3 ppmv	2610.7 ppmv
Uncontrolled NOX (3)	410.40 Lb / Hr	259.74 Lb / Hr	123.66 Lb / Hr	84.24 Lb / Hr
NOX control eff'y (2)	45%	45%	45%	45%
NOX Removed	184.7 Lb / Hr	116.9 Lb / Hr	55.6 Lb / Hr	37.9 Lb / Hr
NOX Removed	1.69E-05 Lb / scf flue gas	1.93E-05 Lb / scf flue gas	2.76E-05 Lb / scf flue gas	2.45E-05 Lb / scf flue gas
NOX from Natural Gas Combustion (4)	4.46E-06 Lb / scf flue gas	4.42E-06 Lb / scf flue gas	0.00E+00 Lb / scf flue gas	0.00E+00 Lb / scf flue gas
Net NOX Reduction	1.25E-05 Lb / scf flue gas	1.49E-05 Lb / scf flue gas	2.76E-05 Lb / scf flue gas	2.45E-05 Lb / scf flue gas
Natural Gas Eff'y	80.0%	80.0%	80.0%	80.0%
Natural Gas Req'd	31.8 Btu / scf flue gas	31.6 Btu / scf flue gas	31.8 Btu / scf flue gas	31.8 Btu / scf flue gas
Natural Gas Req'd	3.18E-05 MMBtu/scf flue gas	3.16E-05 MMBtu/scf flue gas	3.18E-05 MMBtu/scf flue gas	3.18E-05 MMBtu/scf flue gas
Natural Gas Cost (5)	\$9.44 / MMBtu	\$9.44 / MMBtu	\$9.44 / MMBtu	\$9.44 / MMBtu
Natural Gas Cost	\$24.13 / Lb NOX Removed	\$20.05 / Lb NOX Removed	\$10.89 / Lb NOX Removed	\$12.27 / Lb NOX Removed
Annual Natural Gas Cost (6)	\$28,748,554	\$15,822,314	\$5,307,425	\$4,075,344

## User inputs used in calculations

- (1) Average of the latest stack test data for flow and temperature.
- (2) SNCR temperature & efficiency from EPA Control Cost Manual, 6th Ed., NOX Controls, Fig 1.5. (Maximum uncontrolled NOX concentration displayed is 200 ppm.)
- (3) Utilizes the permit limits or potential-to-emit values in tpy based on 8760 hrs/yr.
- (4) Based on 140 lb NOX per MMscf natural gas
- (5) Average utility gas rate, 2013, from US Bureau of Labor Statistics ([www.bls.gov](http://www.bls.gov)) for Pennsylvania Industrial Consumers.
- (6) Annual NG Cost = \$/MMBtu NG x MMBtu/scf flue gas x scf flue gas/hr x 8760 hrs/yr

### Scrubber Costs for Coke Battery Pushing Emissions

Source	SO <sub>2</sub> tpy (2017)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Exhaust Rate (acfm)	Exhaust Rate (dcfm)	Annualized Costs (\$/yr) <sup>2</sup>	Cost Effectiveness (\$/ton)
Coke Battery 1 Pushing	2.06	0.21	1.85	43,203	31,195	598,085	323,075
Coke Battery 2 Pushing	2.06	0.21	1.85	43,203	31,195	598,085	323,075
Coke Battery 3 Pushing	2.06	0.21	1.85	43,203	31,195	598,085	323,075
Coke Battery 13 Pushing	1.72	0.17	1.54	41,871	30,233	586,949	379,992
Coke Battery 14 Pushing	1.72	0.17	1.54	41,871	30,233	586,949	379,992
Coke Battery 15 Pushing	1.72	0.17	1.54	41,871	30,233	586,949	379,992
Coke Battery 19 Pushing	2.68	0.27	2.42	61,808	44,628	741,442	307,012
Coke Battery 20 Pushing	2.68	0.27	2.42	61,808	44,628	741,442	307,012
Coke Battery B Pushing	52.92	5.29	47.63	409,884	295,954	2,307,009	48,434
Coke Battery C Pushing	23.52	2.35	21.16	173,239	125,086	1,376,069	65,017

[1] Average of estimates received from SO<sub>2</sub> scrubber vendors is \$320,000/yr, for a 11,000 dscfm system designed to control SO<sub>2</sub> from a fly ash beneficiation system. Annualized cost includes all operating and maintenance costs, including utilities, materials, labor, and overhead, and also includes capital cost, amortized over a 20-year economic life at 8% interest rate

[2] Estimated via "six-tenths rule," as follows: \$598,085/yr = \$320,000/yr \* ( 31,195 / 11,000 )<sup>0.6</sup>

### FGD Costs for Boilers

Source	Control	Rating (MMBTUH)	SO <sub>2</sub> tpy (2017)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Capital Cost (2019 \$)	O&M Cost (2019 \$/yr)	CRF - 20 years @ 8% Interest	Annualized Costs (\$/yr)	Cost Effectiveness (\$/ton)
Boiler 1	WFGD	760	109.87	10.99	98.88	29,273,396	936,749	0.1019	3,918,309	39,626
Boiler 1	DFGD	760	109.87	10.99	98.88	35,128,075	1,170,936	0.1019	4,748,808	48,025
Boiler 2	WFGD	481	121.44	12.14	109.29	18,526,978	592,863	0.1019	2,479,877	22,690
Boiler 2	DFGD	481	121.44	12.14	109.29	22,232,374	741,079	0.1019	3,005,496	27,499
Boiler 5	WFGD	229	0.27	0.03	0.24	8,820,536	282,257	0.1019	1,180,648	4,821,752
Boiler 5	DFGD	229	0.27	0.03	0.24	10,584,644	352,821	0.1019	1,430,891	5,843,739
Boiler 6	WFGD	229	6.63	0.66	5.97	8,820,536	282,257	0.1019	1,180,648	197,896
Boiler 6	DFGD	229	6.63	0.66	5.97	10,584,644	352,821	0.1019	1,430,891	239,841
Boiler 7	WFGD	156	5.78	0.58	5.20	6,008,750	192,280	0.1019	804,284	154,619
Boiler 7	DFGD	156	5.78	0.58	5.20	7,210,500	240,350	0.1019	974,755	187,391
Boiler 8	WFGD	156	5.70	0.57	5.13	6,008,750	192,280	0.1019	804,284	156,797
Boiler 8	DFGD	156	5.70	0.57	5.13	7,210,500	240,350	0.1019	974,755	190,031

[1] Costs are based on EPA's Air Pollution Control Technology Fact Sheet, which provides ranges for capital and O&M costs, relative to heat input capacity. Costs for FGD for the boilers were estimated using the lower end of these ranges.

## **Appendix B. RBLC RESULTS FOR SCOT PLANT**

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Technology Transfer Network  
Clean Air Technology Center - RACT/BACT/LAER Clearinghouse

## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.  
Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)
[New Search](#)
[Search Results](#)
[Facility Information](#)
[Process List](#)
[Process Information](#)

**Pollutant Information**

[Help](#)
**FINAL**
**RBLC ID:** WY-0056

**Corporate/Company:** LOUISIANA LAND & EXPLORATION CO. - LOST CABIN GAS

**Facility Name:** LA LAND & EXPLORATION CO. - LOST CABIN GAS PLANT

**Process:** CLAUS/ SCOT SULFUR RECOVERY UNITS, TRAIN 3

**Pollutant:** Sulfur Dioxide (SO<sub>2</sub>)

**CAS Number:** 7446-09-5

**Pollutant Group(s):** InOrganic Compounds, Oxides  
of Sulfur (SO<sub>x</sub>),

**Substance Registry System:** Sulfur Dioxide (SO<sub>2</sub>)
**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** N

**P2/Add-on Description:** SEE POLLUTANT NOTES

**Test Method:**

Unspecified

[EPA/OAR Methods](#)
[All Other Methods](#)
**Percent Efficiency:**

0

**Compliance Verified:**
**EMISSION LIMITS:**
**Case-by-Case Basis:**

BACT-PSD

**Other Applicable Requirements:**
**Other Factors Influence Decision:**
**Emission Limit 1:**

312.0000 LB/H See Pollutant Notes

**Emission Limit 2:**

1367.0000 T/YR See Pollutant Notes

**Standard Emission Limit:**

0

**COST DATA:**
**Cost Verified?**

No

**Dollar Year Used in Cost Estimates:**
**Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

Overall sulfur recovery to be no less than 99.8% from the Claus/Scot Unit. Tail gas incinerator treats H<sub>2</sub>S and other sulfur compounds that are emitted by the Claus/Scot process and, as a result, generates SO<sub>2</sub>.



## Exhibit 2

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**GCC Rio Grande - Pueblo Cement Plant**  
**Pueblo, Colorado**

**Four-Factor Reasonable Progress Analysis**

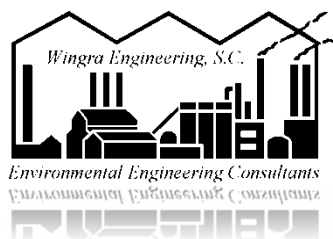
**October 5, 2021**

*Prepared by:*

*Steven Klafka, P.E., BCEE*

*Wingra Engineering, S.C.*

*Madison, Wisconsin*



## 1.0 INTRODUCTION

The Colorado Department of Public Health and Environment (CDPHE) Air Pollution Control Division is updating its regional haze state implementation plan to improve visibility in certain national parks and wilderness areas in the state. These are referred to as Class I areas for implementation of air pollution protection regulations.

CDPHE is evaluating the retrofit of emission control technology at large industrial sources to make reasonable progress toward natural conditions in Class 1 areas. To determine the effectiveness of retrofitting emissions control technology, USEPA requires states to use a Four-Factor Reasonable Progress Analysis (FFA).

The four statutory factors included in an FFA are:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality impacts of compliance
- Remaining useful life of any potentially affected sources

CDPHE has identified the GCC Rio Grande - Pueblo Cement Plant located in Pueblo, Colorado as potentially having impacts on regional haze at surrounding Class I areas. CDPHE recently conducted its own FFA entitled, *Regional Haze Second 10-year Planning Period, Reasonable Progress Four-Factor Analysis of Control Options for GCC Rio Grande - Pueblo Cement Plant*, August 2021.

This report updates the CDPHE analysis by incorporating recent improvements in available air pollution control systems for cement kilns. The CDPHE analysis did not address these control methods.

## 2.0 FACILITY DESCRIPTION

GCC Rio Grande - Pueblo Cement Plant is located at 3372 Lime Road in Pueblo, Colorado. It manufactures Portland cement. This requires that a mixture of quarried materials, including limestone and clay, be heated at high temperatures in a rotary pre-heater/pre-calciner kiln. This kiln is the primary source of air pollution emissions at the plant and is identified as Emission Point 039. The plant has not been issued an air quality operating permit. It currently operates following the requirements summarized in Facility Wide Construction Permit No. 98PB0893 Issuance 8 Correction.<sup>1</sup>

The kiln has a rated capacity of 3,750 tons per day and is fired with coal, natural gas and tire derived fuel. Currently, emissions are controlled using the following methods:

- Particulate Matter (PM) – Baghouse
- Sulfur Dioxide (SO<sub>2</sub>) – Scrubbing inherent in the contact of SO<sub>2</sub> with the alkaline materials in the kiln.
- Nitrogen Oxides (NO<sub>x</sub>) – Use of Selective Non-catalytic Reduction or SNCR by injection of ammonia into the high temperature areas of the kiln.

Allowable and uncontrolled emissions in units of tons per year (tpy) from the kiln are summarized in Table 1. Uncontrolled emissions for PM and NO<sub>x</sub> are based on USEPA emission factors of 250 and 4.2 lbs/ton, respectively. For SO<sub>2</sub>, it has been assumed that there is no difference between the allowable and uncontrolled emissions since the uncontrolled emissions are naturally controlled by the kiln.

Supporting calculations are provided in Appendix A.

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<sup>1</sup> Colorado Department of Public Health and Environment, Air Pollution Control Division, Field Inspection Report, January 22, 2020.

***Table 1 - Allowable and Uncontrolled Emissions from GCC Rio Grande - Pueblo Cement Kiln (tpy)***

Air Pollutant	PM <sub>10</sub> (Total) <sup>a</sup>	SO <sub>2</sub>	NO <sub>x</sub>	Total
Allowable	329.6	943.4	1,100.0	2,373.0
Uncontrolled	216,968.8	943.4	2,874.4	220,786.5

<sup>a</sup> PM<sub>10</sub> (Total) Allowable includes 36.0 tpy filterable and 293.6 tpy condensable.

### **3.0 CDPHE FOUR-FACTOR ANALYSIS**

The Four-Factor Analysis or FFA completed by CDPHE concluded that no emission control systems or methods are available for the GCC kiln. No changes were made to the allowable emissions from the kiln or the plant. A copy of their draft analysis is provided in Appendix B.

For the control of NO<sub>x</sub>, CDPHE evaluated the use of Selective Catalytic Reduction (SCR) to replace the current Selective Non-catalytic Reduction (SNCR). CDPHE estimated the current SNCR is achieving a NO<sub>x</sub> emission reduction of 53.6%. SCR has been shown to provide NO<sub>x</sub> emission reduction of 90% or more. SNCR requires the injection of ammonia in high temperatures (1,600 to 2,000°F) while SCR requires the injection of ammonia at lower temperatures (450 to 800°F) where control occurs in a ceramic catalyst. CDPHE rejected the use of SCR to attain greater NO<sub>x</sub> emission reductions due to the likelihood of catalyst plugging by PM, mostly the condensable form, and the lack of experience on cement kilns.

For the control of PM, CDPHE determined that the existing baghouse provided state of the art capture of filterable PM and no better controls were available. The large amount of condensable PM could be minimized by tight control of the ammonia injection used by the SNCR control system for NO<sub>x</sub>. CDPHE concluded in its FFA that: “These inorganic ammonium salts form when excess ammonia from the SNCR, known as ammonia slip, reacts with chlorides and sulfates from the raw materials and coal.”

For the control of SO<sub>2</sub>, CDPHE did not evaluate control methods since actual emissions from the inherent scrubbing within the kiln were already low.

#### 4.0 OTHER AVAILABLE EMISSION CONTROL SYSTEMS

There are practical impediments to using a traditional SCR control system for the kiln due to potential plugging by PM emissions. However, the shortcomings of traditional SCR have been overcome with the availability of recently available catalytic ceramic filter systems. These systems are in use throughout the U.S., but with limited application at cement plants. There is greater application of these systems at cement plants in Europe. These systems combine the PM removal conducted by a baghouse with the NO<sub>x</sub> removal of SCR. In its FFA, the CDPHE did not evaluate the use of ceramic filter systems.

The advantages of catalytic ceramic filter systems are as follows:

1. Injection of ammonia at low SCR filter temperatures rather than the high SNCR temperatures, thus avoiding the formation of condensable PM within the kiln.
2. More efficient usage of ammonia reducing ammonia slip.
3. Larger reductions in NO<sub>x</sub> emissions, as the control efficiency is increased from 54% (estimated by CDPHE for GCC) to greater than 90%.
4. Simultaneous capture PM emissions.
5. Simultaneous control of SO<sub>2</sub> emissions when combined with reagent injection.

There are two design alternatives for catalytic ceramic filters:

1. Stand-alone catalytic ceramic filter systems
2. Catalytic ceramic filter inserts for existing baghouses

Manufacturers of these filter systems include: Tri-Mer <sup>2</sup>, GEA Bischoff <sup>3</sup>, and Haldor Topsoe A/S<sup>4</sup>. All three firms were contacted for this study. They all cite the ability to control emissions in the cement industry. The first two firms offer catalytic ceramic filters. These catalytic ceramic filter systems combine into a single control device the traditional separate systems for each air pollutant, as the systems typically include a scrubber for SO<sub>2</sub> neutralization, baghouse for PM capture and SCR for NO<sub>x</sub> control. Brochures for the catalytic ceramic filter control systems offered by these two firms are provided in Appendices C and D, respectively.

The last firm, Haldor Topsoe, produces both: 1) a catalytic filter candle (called TopFrax) and 2) a catalytic filter bag (called Cataflex). The filter candles are similar to those used inside the Tri-Mer and GEA systems. The catalytic filter bag, however, is a product that can be added to an existing

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<sup>2</sup> <https://tri-mer.com/hot-gas-treatment/hot-gas-filtration.html>

<sup>3</sup> <https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp>

<sup>4</sup> <https://www.topsoe.com/products/catalysts/topfraxtm>



baghouse. These catalytic filter bags have the advantage of reduced cost. They avoid the need for a separate stand-alone control system by instead inserting the catalytic filter bags into the fabric bags of the existing baghouse used to control PM emissions. Brochures for both the catalytic filter candles and bags provided by Haldor Topsoe are provided in Appendix E. Tri-Mer notes that it also has experience with the installation of catalytic filter bags on existing baghouses.

Tri-Mer has extensive experience in the U.S. using their catalytic filter control systems to simultaneously control PM, SO<sub>2</sub> and NO<sub>x</sub> emissions from high temperature glass furnaces. Current installations in the U.S are summarized in Table 2.

Tri-Mer also has updated existing baghouses by replacing the fabric filter bags with catalytic ceramic filters. This approach modifies the baghouse to allow the control of NO<sub>x</sub> emissions on the ceramic filter while continuing to capture PM emissions. With the addition of reagent injection, these new filters can also control SO<sub>2</sub> emissions.

**Table 2 - Tri-Mer Filter Projects in U.S.**

Company	Location	Glass Type
Durand	Millville, NJ	Tableware
Anchor	Monaca, PA	Mixed
AGC	Church Hill, TN	Flat
Gallo	Modesto, CA	Container
AGC	Hill, KS	Flat
Adagh	Dolton, IL	Container
Kohler	Kohler, WI	Specialty
Guardian	Carleton, MI	Flat
PG Corporation	L.A. Basin	Specialty
Cardinal FG	Mooresville, NC	Flat
Cardinal FG	Durant, OK	Flat

Haldor Topsoe worked with FLSmidth to install a ceramic filter system after a baghouse used on the cement kiln at Cemex Southeast LLC cement plant in Demopolis, Alabama. This ceramic filter system was used to control organic hazardous organic compound emissions.<sup>5</sup> Haldor Topsoe have also used their catalytic filter bags to control NO<sub>x</sub> emissions from cement kilns in Europe.

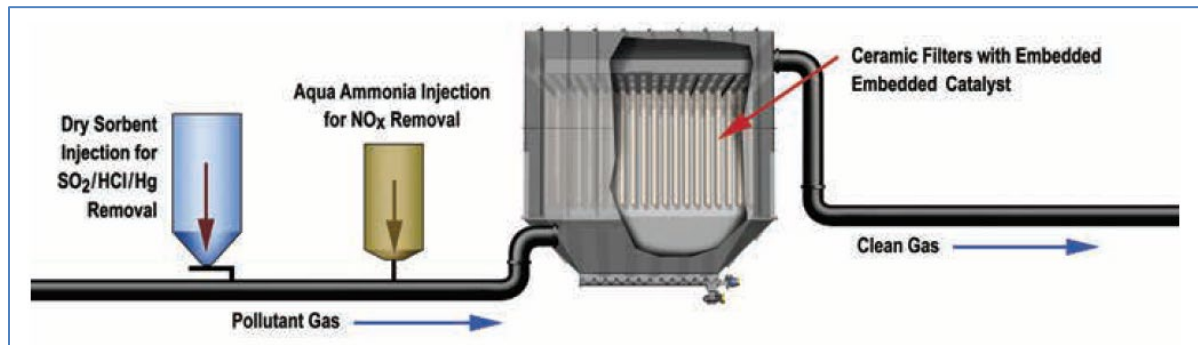
Figure 1 provides a diagram of a stand-alone catalytic ceramic filter system offered by Tri-Mer.

Figure 2 shows the catalytic filter bag inserts (called Cataflex) offered by Haldor Topsoe.

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<sup>5</sup> <https://www.cemex.com/documents/20143/49694544/IntegratedReport2019.pdf/4e1b2519-b75f-e61a-7cce-2a2f2f6f09dc>

It is noteworthy that CDPHE recently completed an FFA for the Rocky Mountain Bottle Company which has a glass furnace equipped with the Tri-Mer system.



**Figure 1 - Catalytic Ceramic Filter System**



**Figure 2 - Catalytic Filter Bag Insert**

The configuration of the existing GCC Rio Grande - Pueblo cement plant has been discussed with the three vendors. Potential emission control options include the following:

1. Insertion of catalytic filters into the existing baghouse.
2. Installation of a ceramic filter system after the existing baghouse.
3. Replacement of the existing baghouse with a stand-alone ceramic filter system.

The least expensive option is the first – installing catalytic filter bags into the fabric bags of the existing baghouse or replacing the fabric bags with ceramic filter elements. This approach would retain the footprint of the existing baghouse and stack with the least physical modifications.

The remaining two options would be more costly and require the purchase of a stand-alone ceramic filter system. For the second option, the existing baghouse and SNCR system would be retained. There would be less air pollution emissions to control and additional cost to reheat the flue gas to the catalyst operating temperature. For the third option, the existing baghouse and SNCR system would be removed. There would be more air pollution emissions to control and no need to reheat the flue gas.

## 5.0 COSTS OF COMPLIANCE

Cost estimates were developed for the following three emission control alternatives not considered by CDPHE in its FFA:

1. Replacement of the fabric filter bags of the existing baghouse with catalytic ceramic filter elements. This approach would add the control of NO<sub>x</sub> and SO<sub>2</sub> emissions.
2. Installation of a stand-alone Tri-Mer catalytic ceramic filter system, while retaining the existing baghouse, SNCR and wet scrubber control systems. This approach would simultaneously control PM, SO<sub>2</sub> and NO<sub>x</sub> emissions.
3. Replacement of the existing baghouse and wet scrubber with a stand-alone Tri-Mer catalytic ceramic filter system. This approach would simultaneously control PM, SO<sub>2</sub> and NO<sub>x</sub> emissions

### 5.1 Cost of Catalytic Filters (Option #1)

Tri-Mer was provided with the design specifications of the existing cement kiln. These are the same as those used to develop the cost estimates for a stand-alone catalytic ceramic filter system, as discussed below.

Based on the design of the existing cement kiln and its air pollution control system, Tri-Mer prepared a proposal to replace the existing fabric filter bags in the baghouse with catalytic ceramic filter elements. This approach would continue to provide control of PM emissions, but adds the ability to control NO<sub>x</sub> emissions by 90% or more. Additionally, reagent injection has been included in the proposal to control SO<sub>2</sub> emissions by 80% or more. A copy of the Tri-Mer proposal is provided in Appendix F of this report.

Tri-Mer assumed the existing SNCR system would be discontinued so uncontrolled NO<sub>x</sub> emissions would be controlled by the new filters. To achieve the required operating temperature of 550 °F, the exhaust flue gas of the cement kiln would no longer be cooled to a temperature required by the existing fabric bags.

Table 3 summarizes the cost estimate for Option #1. Tri-Mer estimates a cost effectiveness of \$1,438 per ton of NO<sub>x</sub> removed. This estimate is reasonable and falls within the range that has been accepted by regulatory agencies. If the removal of uncontrolled SO<sub>2</sub> and PM emissions is considered, the combined cost effectiveness is further reduced to \$21 per ton of NO<sub>x</sub>, SO<sub>2</sub> and PM removed.

Other benefits of this control option cited by Tri-Mer include the following:

- Minimal catalyst plugging
- Reduced ammonia slip

- Negligible catalyst deactivation
- Minor conversion of SO<sub>2</sub> to SO<sub>3</sub>

Each of these addresses concerns raised by CDPHE for the use of SCR in its draft FFA.

## **5.2 Cost of Catalytic Ceramic Filter System (Options #2 and #3)**

For typical Best Available Control Technology analyses, order-of-magnitude cost estimates are typically generated.<sup>6</sup> The cost estimate is improved if it is based on actual vendor quotations for the required equipment. Developing air pollution control cost estimates is a time-consuming process. Rather than request budget quotations from vendors, a cost estimate was developed from a 2015 proposal for a Tri-Mer catalytic ceramic filter system sized for a 700 tons per day flat glass plant. This system was eventually installed in North Carolina and continues to operate successfully. This glass plant cost estimate reflects the retrofit of a new control system at an existing industrial facility.

The capital, installation and operating costs were adjusted to reflect the differences between the glass plant and the cement kiln at the GCC Rio Grande - Pueblo cement plant. Adjustments accounted for inflation, inlet air flow rates and uncontrolled emission rates of PM, SO<sub>2</sub> and NO<sub>x</sub>. Supporting cost estimation calculations are provided in Appendix A.

If the existing baghouse is retained for the first option, the exit temperature of the flue gas would be too low for the use of a catalytic reduction system. The cost estimates include the cost of natural gas to reheat the flue gas to the control system operating temperature of 550 °F.

If the existing baghouse is removed and replaced with the catalytic filter system for the second option, it was assumed that operation of the cement plant gas cooler prior to the baghouse could instead be adjusted to increase the flue gas temperature to that required for the catalyst.

Table 3 summarizes the cost estimate for Options #2 and #3. Because the catalytic ceramic filter system is a multi-pollutant control technology, cost effectiveness was calculated based on the total expected emission reductions of NO<sub>x</sub> alone, and for PM, SO<sub>2</sub> and NO<sub>x</sub> combined.

For Option #2, adding a new ceramic catalytic filter system after the existing baghouse and SNCR system, the estimated cost effectiveness to is \$6,211 per ton for the removal of NO<sub>x</sub> emissions. The cost effectiveness is \$3,550 per ton for the removal of combined emissions of PM, SO<sub>2</sub> and NO<sub>x</sub>. This is based on controlling the allowable emissions exiting the current baghouse and SNCR system.

For Option #3, replacement of the existing baghouse and SNCR system with a new ceramic catalytic filter system, estimated cost effectiveness is \$1,889 per ton for the removal of NO<sub>x</sub>

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<sup>6</sup> USEPA, *Air Pollution Control Manual, Sixth Edition*, EPA/452/B-02-001 January 2002.

emissions. The cost effectiveness is \$28 per ton for the removal of combined emissions of PM, SO<sub>2</sub> and NO<sub>x</sub>. This is based on controlling the uncontrolled emissions exiting the current cement kiln.

This analysis for a stand-alone catalytic ceramic control system shows that Option #2 has a cost effectiveness value for all pollutants combined which is reasonable and falls within the range that has been accepted by regulatory agencies. Option #3 has cost effectiveness values for NO<sub>x</sub> alone, or all pollutants combined, which are reasonable and falls within the range that has been accepted by regulatory agencies.

**Table 3 - Cost Estimate for Catalytic Ceramic Filters for GCC Rio Grande - Pueblo**

<b>Capital Costs</b>	Option #1	Option #2	Option #3
Location of New Catalytic Filters	Replace Filters	After Baghouse	Replace Baghouse
Emissions Basis	Uncontrolled	Allowable	Uncontrolled
Basis	Tri-Mer Proposal	Scaled Quotation	Scaled Quotation
<b>Combined Capital and Operating Costs</b>			
Capital Costs	\$9,589,200	\$31,278,404	\$31,278,404
Annual Capital Costs	\$479,460	\$2,151,329	\$2,151,329
Annual Operating Costs	\$3,241,780	\$3,997,812	\$2,734,363
Annual Capital and Operating Costs	\$3,721,240	\$6,149,141	\$4,885,692
Inlet NO <sub>x</sub> (tpy)	2,874	1,100	2,874
Inlet SO <sub>2</sub> (tpy)	943	943	943
Inlet PM (tpy)	171,094	36	171,094
Inlet NO <sub>x</sub> , SO <sub>2</sub> and PM (tpy)	174,912	2,079	174,912
Outlet NO <sub>x</sub> (tpy)	287	110	287
Outlet SO <sub>2</sub> (tpy)	189	236	236
Outlet PM (tpy)	36	2	36
Outlet NO <sub>x</sub> , SO <sub>2</sub> and PM (tpy)	512	347	560
Removed NO <sub>x</sub> (tpy)	2,587	990	2,587
Removed SO <sub>2</sub> (tpy)	755	708	708
Removed PM (tpy)	171,057	35	171,057
Removed NO <sub>x</sub> , SO <sub>2</sub> , and PM (tpy)	174,399	1,732	174,352
Cost Effectiveness (\$ per ton of NO <sub>x</sub> removed)	\$1,438	\$6,211	\$1,889
Cost Effectiveness (\$ per ton of total removed)	\$21	\$3,550	\$28
Proposed Limitation for NO <sub>x</sub> (lbs/ton of clinker) (30-day rolling average)	0.42	0.16	0.42
Proposed Limitation for SO <sub>2</sub> (lbs/ton of clinker) (30-day rolling average)	0.28	0.34	0.34
Proposed Limitation for PM (lbs/ton of clinker) (30-day rolling average)	0.05	0.002	0.05

## **6.0 TIME NECESSARY FOR COMPLIANCE**

Based on prior projects, the time frame to obtain a quotation for a catalytic ceramic filter system or catalytic filter bags, issue a purchase order, complete engineering, construct and install the equipment is 12 months.

## **7.0 ENERGY AND NON-AIR QUALITY IMPACTS OF COMPLIANCE**

Significant operating costs include electricity, ammonia reagent, hydrated lime reagent and labor. These costs are taken into account in the enclosed cost estimates. The cost estimates provided in this report incorporate electricity usage for control system fans.

The ammonia selected for the control of NO<sub>x</sub> emissions is 19% aqueous ammonia. This is a less concentrated and safer alternative to anhydrous ammonia. This type of ammonia has no federal requirement to evaluate the potential impacts of an accidental release.

The calcium sulfate (i.e., gypsum) formed by the reaction of hydrated lime with SO<sub>2</sub> will be captured as dust by the ceramic filters. Calcium sulfate is a raw material in cement. It is possible the capture dust can be used as one of the ingredients in the production of cement and avoid landfilling.

## **8.0 REMAINING USEFUL LIFE OF ANY POTENTIALLY AFFECTED SOURCES**

In its FFA, CDPHE concluded that Holcim has not announced a closure date for the Florence kiln, and CDPHE assumed that the cement kiln will remain in operation for at least 20 years.

## 9.0 CONCLUSIONS

The draft FFA prepared by CDPHE for the GCC Rio Grande - Pueblo cement plant concluded there were no feasible control systems available to further reduce emissions. The use of catalytic ceramic filter systems was not considered by CDPHE. These systems are in operation in the U.S. and are suitable for cement kilns.

The enclosed estimates show that for the first option, replacement of the existing fabric filter bags with catalytic ceramic filter elements, the cost effectiveness would be \$1,438 per ton for the removal of NO<sub>x</sub> emissions. The cost effectiveness is \$21 per ton for the removal of combined emissions of PM, SO<sub>2</sub> and NO<sub>x</sub>. This is based on controlling the uncontrolled emissions exiting the current cement kiln.

For the second option, adding a new ceramic catalytic filter system after the existing baghouse and SNCR system, the estimated cost effectiveness to is \$6,211 per ton for the removal of NO<sub>x</sub> emissions. The cost effectiveness is \$3,550 per ton for the removal of combined emissions of PM, SO<sub>2</sub> and NO<sub>x</sub>. This is based on controlling the allowable emissions exiting the current baghouse and SNCR system.

For the third option, replacement of the existing baghouse and SNCR system with a new ceramic catalytic filter system, estimated cost effectiveness is \$1,889 per ton for the removal of NO<sub>x</sub> emissions. The cost effectiveness is \$28 per ton for the removal of combined emissions of PM, SO<sub>2</sub> and NO<sub>x</sub>. This is based on controlling the uncontrolled emissions exiting the current cement kiln.

Except for controlling only NO<sub>x</sub> just with the first option, all of these cost effectiveness values represent a reasonable expenditure for the reduction of PM, SO<sub>2</sub>, and NO<sub>x</sub> emissions. There are no other impediments to the use of these control systems associated with time of installation, energy and non-air impacts, or the anticipated life of the existing cement plant.



# Appendix A

## Supporting Cost Calculations

Facility	GCC Rio Grande			Reference
	Pueblo Cement Plant			A
	Pueblo, Colorado			A
	Preheater/Precalciner Kiln			A
AIRS Point	039			A
Fuels	Coal, NG, TDF			A
Capacity (tons per day)	3,750			A
Current Control for PM	Baghouse			A
Current Control for SO <sub>2</sub>	Inherent Scrubbing			A
Current Control for NO <sub>x</sub>	SNCR			A
Exhaust Flow Rate (acfm)	306,708			B
Exhaust Temperature (F)	377			B
Exhaust Moisture (%)	8.2			B
	Air Pollutant	Units	Emission	
Allowable	PM <sub>10</sub> (Filterable)	(tpy)	36.0	A
	PM <sub>10</sub> (Condensable)	(tpy)	293.6	A
	PM <sub>10</sub> (Total)	(tpy)	329.6	A
	SO <sub>2</sub>	(tpy)	943.4	A
	NO <sub>x</sub>	(tpy)	1,100.0	A
Allowable	PM <sub>10</sub> (Filterable)	(lbs/ton)	0.1	Calculated
	PM <sub>10</sub> (Condensable)	(lbs/ton)	0.4	Calculated
	PM <sub>10</sub> (Total)	(lbs/ton)	0.5	Calculated
	SO <sub>2</sub>	(lbs/ton)	1.4	Calculated
	NO <sub>x</sub>	(lbs/ton)	1.6	Calculated
Allowable	PM <sub>10</sub> (Filterable)	(lbs/hr)	8.2	Calculated
	PM <sub>10</sub> (Condensable)	(lbs/hr)	67.0	Calculated
	PM <sub>10</sub> (Total)	(lbs/hr)	75.3	Calculated
	SO <sub>2</sub>	(lbs/hr)	215.4	Calculated
	NO <sub>x</sub>	(lbs/hr)	251.1	Calculated
Uncontrolled	PM <sub>10</sub> (Filterable)	(lbs/ton)	250.0	C
	PM <sub>10</sub> (Condensable)	(lbs/ton)	67.0	A
	PM <sub>10</sub> (Total)	(lbs/ton)	317.0	Calculated
	SO <sub>2</sub>	(lbs/ton)	1.4	D
	NO <sub>x</sub>	(lbs/ton)	4.2	A
Uncontrolled	PM <sub>10</sub> (Filterable)	(lbs/hr)	39,062.5	Calculated
	PM <sub>10</sub> (Condensable)	(lbs/hr)	10,473.7	Calculated
	PM <sub>10</sub> (Total)	(lbs/hr)	49,536.2	Calculated
	SO <sub>2</sub>	(lbs/hr)	215.4	Calculated
	NO <sub>x</sub>	(lbs/hr)	656.3	Calculated
Uncontrolled	PM <sub>10</sub> (Filterable)	(tpy)	171,093.8	Calculated
	PM <sub>10</sub> (Condensable)	(tpy)	45,875.0	Calculated
	PM <sub>10</sub> (Total)	(tpy)	216,968.8	Calculated
	SO <sub>2</sub>	(tpy)	943.4	Calculated
	NO <sub>x</sub>	(tpy)	2,874.4	Calculated

A - CDPHE, Regional Haze Second 10-year Planning Period, Reasonable Progress Four-Factor Analysis of Control Options for

B - GCC Rio Grande, Inc., Portland Cement Manufacturing Facility, Pueblo County, Colorado, Revised Initial Title V Operating

C - USEPA, AP42, Table 11.6-2 - Emission Factors for Portland Cement Manufacturing, January 1995.

D - Uncontrolled SO<sub>2</sub> assumed to be same as allowable due to use of inherent scrubbing within kiln.

Air Pollutant	PM <sub>10</sub> (Filterable)	PM <sub>10</sub> (Condensable)	PM <sub>10</sub> (Total)	SO <sub>2</sub>	NO <sub>x</sub>	Total
Allowable	36.0	293.6	329.6	943.4	1,100.0	2,373.0
Uncontrolled	171,093.8	45,875.0	216,968.8	943.4	2,874.4	220,786.5

	Reference	Original (2015)		Original (2021)	Reference	GCC Rio Grande	GCC Rio Grande
Location of New Catalytic Filters						After Baghouse	Replace Baghouse
Emissions Basis		Potential		Potential		Allowable	Uncontrolled
Capacity (tpd)	Quotation	700		700	2021 CDPHE	3,750	3,750
Current Flow (acfm)					Permit Application	306,708	306,708
Current Temperature (deg F)					Permit Application	377	377
Inlet Flow (acfm)	Quotation	96,745		96,745	Calculated	370,102	370,102
Inlet Temperature (deg F)	Quotation	550		550	Calculated	550	550
Inlet Flow (scfm)							193,479
Inlet NOx (lbs/ton)	Quotation	18.0			Current Allowable	1.6	
Inlet SO2 (lbs/ton)	Quotation	4.0			Current Allowable	1.4	
Inlet PM (lbs/ton)	Quotation	1.2			Current Allowable	0.1	
Inlet NOx (tpy)	Calculated	2,299.5			Current Allowable	1,100	
Inlet SO2 (tpy)	Calculated	511.0			Current Allowable	943	
Inlet PM (tpy)	Calculated	153.3			Current Allowable	36	
NOx Removal (%)	IN vs OUT	90.0%			Same as Original	90.0%	
SO2 Removal (%)	IN vs OUT	75.0%			Same as Original	75.0%	
PM Removal (%)	IN vs OUT	95.8%			Same as Original	95.8%	
Outlet NOx (lbs/ton)	Quotation	1.8			Calculated	0.16	
Outlet SO2 (lbs/ton)	Quotation	1.0			Calculated	0.34	
Outlet PM (lbs/ton)	Quotation	0.1			Calculated	0.002	
Outlet NOx (tpy)	Calculated	230.0			Calculated	110.0	
Outlet SO2 (tpy)	Calculated	127.8			Calculated	235.9	
Outlet PM (tpy)	Calculated	6.4			Calculated	1.5	
Removed NOx (tpy)	Calculated	2,069.6			Calculated	990.0	
Removed SO2 (tpy)	Calculated	383.3			Calculated	707.6	
Removed PM (tpy)	Calculated	146.9			Calculated	34.5	
Removed NOx, SO2 and PM (tpy)	Calculated	2,599.7			Calculated	1,732.1	
Inlet NOx (lbs/ton)	Quotation	18.0		18.0	Uncontrolled (USEPA)		4.2
Inlet SO2 (lbs/ton)	Quotation	4.0		4.0	Current Allowable		1.4
Inlet PM (lbs/ton)	Quotation	1.2		1.2	Uncontrolled (USEPA)		250
Inlet NOx (tpy)	Calculated	2,299.5		2,299.5	Calculated		2,874.4
Inlet SO2 (tpy)	Calculated	511.0		511.0	Calculated		943
Inlet PM (tpy)	Calculated	153.3		153.3	Calculated		171,093.8
NOx Removal (%)	IN vs OUT	90.0%		90.0%	Same as Original		90.0%
SO2 Removal (%)	IN vs OUT	75.0%		75.0%	Same as Original		75.0%
PM Removal (%)	IN vs OUT	95.8%		95.8%	Same as Original		95.8%
Outlet NOx (lbs/ton)	Quotation	1.8		1.8	Calculated		0.42
Outlet SO2 (lbs/ton)	Quotation	1.0		1.0	Calculated		0.34
Outlet PM (lbs/ton)	Quotation	0.1		0.1	Calculated	Based on 0.005 gr/scf	0.05
Outlet NOx (tpy)	Calculated	230.0		230.0	Calculated		287.4
Outlet SO2 (tpy)	Calculated	127.8		127.8	Calculated		235.9
Outlet PM (tpy)	Calculated	6.4		6.4	Calculated		36.3
Removed NOx (tpy)	Calculated	2,069.6		2,069.6	Calculated		2,586.9
Removed SO2 (tpy)	Calculated	383.3		383.3	Calculated		707.6
Removed PM (tpy)	Calculated	146.9		146.9	Calculated		171,057.4
Removed NOx, SO2 and PM (tpy)	Calculated	2,599.7		2,599.7	Calculated		174,351.9
<b>Capital Costs</b>		Original (2015)	Inflation	Original (2021)	Adjustment Method	GCC Rio Grande	GCC Rio Grande
Location of New Catalytic Filters						After Baghouse	Replace Baghouse
Emissions Basis						Allowable	Uncontrolled
Complete System Equipment and Installation		\$12,159,935	1.15	\$13,983,925	Six-Tenths by Inlet Flow	\$31,278,404	\$31,278,404
Capital Recovery Factor (CRF)	CRF (20 yrs, 3.25%)	0.06878	CRF (20 yrs, 3.25%)		CRF (20 yrs, 3.25%)	0.06878	0.06878
Annualized Capital Cost		\$836,360				\$2,151,329	\$2,151,329
<b>Operating Costs</b>							
Electricity		\$188,953	1.15	\$217,296	Ratio by Inlet Flow	\$831,274	\$831,274
19% Aqueous Ammonia		\$665,665	1.15	\$765,515	Ratio by Inlet NOx	\$366,195.36	\$956,893
Hydrated Lime		\$361,810	1.15	\$416,082	Ratio by Inlet SO2	\$768,162.99	\$768,163
Labor for Operation and Maintenance		\$69,213	1.15	\$79,595	Six-Tenths by Inlet Flow	\$178,033	\$178,033
Natural Gas for Reheating Flue Gas						\$1,854,147	\$0
Annual Operating Costs		\$1,285,641				3,997,812	2,734,363
<b>Combined Capital and Operating Costs</b>							
Capital Costs		\$12,159,935				\$31,278,404	\$31,278,404
Annual Capital Costs		\$836,360				\$2,151,329	\$2,151,329
Annual Operating Costs		\$1,285,641				\$3,997,812	\$2,734,363
Annual Capital and Operating Costs		\$2,122,001				\$6,149,141	\$4,885,692
Inlet NOx (tpy)		2,300				1,100	2,874
Inlet SO2 (tpy)		511				943	943
Inlet PM (tpy)		153				36	171,094
Inlet NOx, SO2 and PM (tpy)		2,964				2,079	174,912
Outlet NOx (tpy)		230				110	287
Outlet SO2 (tpy)		128				236	236
Outlet PM (tpy)		6				2	36
Outlet NOx, SO2 and PM (tpy)		364				347	560
Removed NOx (tpy)		2,070				990	2,587
Removed SO2 (tpy)		383				708	708
Removed PM (tpy)		147				35	171,057
Removed NOx, SO2 and PM (tpy)		2,600				1,732	174,352
Cost Effectiveness (\$ per ton of NOx removed)		\$1,025				\$6,211	\$1,889
Cost Effectiveness (\$ per ton of total removed)		\$816				\$3,550	\$28

## Notes:

Complete System Equipment and Installation includes: emission control system, controls, infrastructure, engineering design and project management, installation, services, batch recycle system, ammonia tank shelter.

Inflation multiplier from November 2015 to August 2021 = 1.15 - [https://www.bls.gov/data/inflation\\_calculator.htm](https://www.bls.gov/data/inflation_calculator.htm)

Capital Recover Factor based on lifetime of operation and % interest from DOE, Four-Factor Analysis, <https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze>

Natural Gas for Reheating Flue Gas to 550 F

Start Temp	(deg F)	377
Start Flow	(acfm)	306,708

Inlet Temp	(deg F)	550
Inlet Flow	(acfm)	370,102
Inlet Flow	(scfm)	193,479
Inlet Flow	(lbs/min)	14,511
Start h	(btu/lbs)	200.83
Inlet h	(btu/lbs)	243.48
Change h	(btu/lbs)	42.65
Fuel Required	(btu/hr)	37,133,434
Fuel Required	(therms/hr)	371.3
Nat Gas	(\$/therm)	0.57
Nat Gas	(\$/yr)	\$1,854,147

Capacity (tpd)	3,750	3,750	3,750
<b>Combined Capital and Operating Costs</b>	Option #1	Option #2	Option #3
Capital Costs	\$9,589,200	\$31,278,404	\$31,278,404
Annual Capital Costs	\$479,460	\$2,151,329	\$2,151,329
Annual Operating Costs	\$3,241,780	\$3,997,812	\$2,734,363
Annual Capital and Operating Costs	\$3,721,240	\$6,149,141	\$4,885,692
Inlet NO <sub>x</sub> (tpy)	2,874	1,100	2,874
Inlet SO <sub>2</sub> (tpy)	943	943	943
Inlet PM (tpy)	171,094	36	171,094
Inlet NO <sub>x</sub> , SO <sub>2</sub> and PM (tpy)	174,912	2,079	174,912
Outlet NO <sub>x</sub> (tpy)	287	110	287
Outlet SO <sub>2</sub> (tpy)	189	236	236
Outlet PM (tpy)	36	2	36
Outlet NO <sub>x</sub> , SO <sub>2</sub> and PM (tpy)	512	347	560
Removed NO <sub>x</sub> (tpy)	2,587	990	2,587
Removed SO <sub>2</sub> (tpy)	755	708	708
Removed PM (tpy)	171,057	35	171,057
Removed NO <sub>x</sub> , SO <sub>2</sub> and PM (tpy)	174,399	1,732	174,352
Cost Effectiveness (\$ per ton of NO <sub>x</sub> removed)	\$1,438	\$6,211	\$1,889
Cost Effectiveness (\$ per ton of total removed)	\$21	\$3,550	\$28
Proposed Limitation for NO <sub>x</sub>	0.42	0.16	0.42
Proposed Limitation for SO <sub>2</sub>	0.28	0.34	0.34
Proposed Limitation for PM	0.05	0.002	0.05

# Appendix B

## CDPHE Four-Factor Analysis

**Regional Haze Second 10-year Planning Period  
Reasonable Progress Four-Factor Analysis of Control Options  
for  
GCC Rio Grande - Pueblo Cement Plant**

**August 2021**

For the second Regional Haze 10-year planning period, Colorado evaluated all stationary sources in the state with oxides of nitrogen (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM) emissions over 25 tons per year (TPY) to determine which sources should be evaluated for potential additional emission controls depending on proximity to Class I areas (CIAs). Sources were included in the Reasonable Progress (RP) analysis if their total emissions of NO<sub>x</sub>, SO<sub>2</sub>, and PM, in TPY, divided by distance to the nearest CIA, in km, ("Q/d") was greater than 10, based on 2014 National Emissions Inventory (NEI) emissions. In Colorado, sources with a Q/d > 10 are considered potential contributors to CIA visibility impairment and are subject to the four-factor review process. Although a facility may have installed controls, changed fuel sources, or made other operational changes since 2014 that have reduced emissions, these sources are still subject to evaluation. For all RP sources, the four factor analyses are conducted using more current baseline emissions, typically 2016-2018 actual emissions. In determining RP under the Regional Haze program, states must consider the four factors explicitly set forth in the Clean Air Act, which are:

- (1) costs of compliance,
- (2) time necessary for compliance,
- (3) energy and non-air quality environmental impacts of compliance, and
- (4) remaining useful life.

The GCC Pueblo cement plant has a Q/d = 12.67. Accordingly, the GCC plant is subject to the RP four-factor review process. Great Sand Dunes National Park is the nearest Class I Area to GCC and is 85.3 km (53.0 miles) from the GCC Pueblo plant. GCC was not analyzed during the first Regional Haze planning period.

For the purposes of evaluating RP, the Division elected to focus its analysis on those individual emission units with actual baseline emissions (2016 - 2018 average emissions) of NO<sub>x</sub>, SO<sub>2</sub>, or PM<sub>10</sub> equal to or exceeding 10 TPY. The Division established a *de minimis* threshold to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

Prior to the application of the four statutory factors, the Division followed a process similar to assessing the application of the Best Available Control Technology (BACT), by identifying the available emissions control technologies and then determining if they were technically and economically feasible.

**I. Source Description**

Facility AIRS ID:	101-0252
Owner/Operator:	GCC Rio Grande
Source Type:	Portland Cement Manufacturing
SCC:	305-006-23 (Kiln), 305-006-14 (Clinker Cooler)



Kiln Type: 305-006-09 (Primary Crusher)  
Preheater/Precalciner Kiln

The GCC facility manufactures Portland cement and is located in Pueblo, Colorado, about 53 miles from Great Sand Dunes National Park. The facility is located in an attainment area for all criteria pollutants.

The GCC Pueblo kiln is the newest Portland cement plant in Colorado and is a modern preheater/precalciner that is much more energy efficient than older kiln designs. This design is much more energy efficient than earlier wet cement kilns which combusted large quantities of fuel to boil off the water in the slurry. It's also more energy efficient than long dry kilns, including the modified long-dry kiln at the CEMEX Lyons facility. The GCC kiln utilizes a 5-stage single string preheater and precalciner where most of the fuel is fired. This requires less overall fuel, resulting in lower emissions of  $\text{NO}_x$ ,  $\text{SO}_2$ , and PM.

The permitted kiln production rate is 3,750 tons per day of clinker, and on average yields approximately 130 tons of clinker per hour. The kiln is the main source of  $\text{PM}_{10}$  and  $\text{NO}_x$  emissions, but its  $\text{SO}_2$  emissions are below the 10 TPY de minimis threshold. The clinker cooler is the only other significant sources of visibility impairing  $\text{PM}_{10}$ , but does not emit  $\text{SO}_2$  or  $\text{NO}_x$ .

#### Process Description:

The basic process of producing Portland cement plant involves producing a raw meal consisting of quarried materials, including limestone (primarily  $\text{CaCO}_3$ , calcium carbonate) and clay (which contains silicate minerals and aluminum oxides), along with other ingredients such as sand (primarily  $\text{SiO}_2$ , silicon dioxide) and scale (iron oxides). These raw meal ingredients are finely ground and mixed in various ratios depending on the desired final cement product. This raw meal is heated to very high temperatures in a rotary kiln to form alite ( $\text{Ca}_3\text{O}\cdot\text{SiO}_4$ ) which clumps together in nodules called clinker, the primary component of Portland cement. In this heating process,  $\text{NO}_x$  is produced from the high combustion temperatures,  $\text{SO}_2$  is produced from sulfur in the coal and sulfur-containing compounds in the limestone, and  $\text{CO}_2$  is produced from the fuel combustion and the decomposition of calcium carbonate into calcium oxide and carbon dioxide ( $\text{CaCO}_3 \rightarrow \text{CaO} + \text{CO}_2$ ). The clinker is cooled, combined with other products, such as gypsum ( $\text{CaSO}_4\cdot 2\text{H}_2\text{O}$ ), and ground to produce a specific Portland cement formulation.

In the case of the GCC Pueblo facility, the process begins with extracting limestone and other raw materials from the co-located quarry, and processing them through a primary crusher at the quarry. Water injection is used to drill blast holes for explosives and sequential blasting is used to minimize emissions for the blasting operations. The primary crusher is mobile and is positioned to minimize transport distance of material to reduce particulate emissions. The crusher is also equipped with a baghouse to control PM emissions. The crushed material is transported to the limestone storage dome by a covered conveyor system. The material is then blended and transferred via another covered conveyor to raw material storage bins. This conveyor and the blending processes are controlled by baghouses.

These storage bins contain limestone and additive materials, such as sandstone and iron. The facility develops the raw material blend by weighing the limestone and additives on weigh scales and transferring these materials to the raw mill by covered conveyor. The raw mill mixes and crushes the materials and delivers the homogenized material to a raw meal storage silo. A conveyor then feeds the raw meal from the storage silo to the preheater/precalciner.



Pulverized coal from the coal mill is also fed to the preheater/precalciner, where it is fired. Some process gases from the kiln are used to dry the coal, while the remaining gases pass through the in-line raw mill. This helps conserve energy and the in-line raw mill acts as a scrubber for SO<sub>2</sub> and ammonia. The material leaving the preheater/precalciner is almost completely calcined as it enters the rotary kiln, which is located at a slight incline along its horizontal axis. The material travels towards the clinker discharge end where additional pulverized coal is fired for the clinking process. The clinker is discharged from the kiln into the clinker cooler where it is cooled by air forced through the clinker bed by under-grate fans. Heated air from the clinker cooler is fed into the kiln as pre-heated combustion air, which improves the energy efficiency of the kiln. The cooled clinker is transferred to the clinker storage dome by a covered conveyor before being transferred by two covered conveyors to a clinker storage silo near the finish mill. Finish mill additives, such as gypsum, are delivered via truck or rail and transferred to an additive storage silo near the finish mill. Clinker and additives from the clinker storage silo and additive silo are fed to the finish mill which grinds the material to a fine powder to produce Portland cement. The Portland cement is stored in product silos and shipped via railcar or truck.

From an overall perspective, the manufacturing process can be viewed as two segments -- clinker production and cement production. The clinker storage allows the two processes to operate at different production rates. During periods of low demand for cement, clinker is accumulated. If cement is in very high demand, the clinker production can be supplemented by purchase of clinker from other sources. The overall result is the clinker production can operate at a relatively steady rate, while the cement production can operate in response to current or projected demands.

For sources identified through the above screening process as potentially impacting western Class I Areas, a *de minimis* threshold was established to focus technical emission control analysis on significant emission units where potential controls could provide a meaningful improvement in visibility. Emission points may include point or fugitive emissions, or both. Identified sources were asked to submit relevant four-factor information for all emission points with 2016 - 2018 average actual baseline emissions of NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub> greater than or equal to 10 TPY. These points were evaluated to identify additional emissions controls to determine if additional emissions reductions are technically feasible and cost effective.

GCC submitted a Four-Factor Analysis for the Kiln (AIRS ID 039) and Clinker Cooler (AIRS ID 040) to the Division on October 30, 2019 with additional information submitted on March 27, 2020 and May 19, 2020.

The emission points potentially subject to evaluation at GCC Pueblo plant are shown in Table 1. Emission points with permitted emissions of less than 10 TPY of NO<sub>x</sub>, SO<sub>2</sub> or PM<sub>10</sub> were excluded.

Table 1: GCC Emission Points

AIRS Point	Description	Emission Type
039	Kiln	Point
040	Clinker Cooler	Point
069	Quarry Crusher Engine	Point

Table 2 lists the permitted and actual emissions for all units with permitted or actual emissions over 10 TPY. Kiln (039) and Clinker Cooler (040) emissions are the 2016-2018



averages reported in the four factor analysis submitted by GCC. Actual emissions for the Quarry Crusher Engine (069) are based on the average of 2016 and 2017 emissions reported on 2017 and 2018 APENs submitted to the Division.

Table 2: GCC Permitted and Average Annual Emissions

Point	Permitted PM <sub>10</sub> (TPY)	Actual PM <sub>10</sub> (TPY)	Permitted SO <sub>2</sub> (TPY)	Actual SO <sub>2</sub> (TPY)	Permitted NO <sub>x</sub> (TPY)	Actual NO <sub>x</sub> (TPY)
039 *	36.01 (F) 293.56 (C)	11.3 (F) 99.0 (C)	943.4	1.1	1,100.0	915.2
040 **	33.92	27.9	N/A	N/A	N/A	N/A
069	N/A	0.8	6.3	5.2	19.3	5.9

\*The kiln PM limit marked with (F) is for filterable emissions and the PM limit marked with (C) is condensable emissions. GCC is the only Colorado cement kiln with a limit on condensable particulate matter.

\*\*The clinker cooler only emits particulates, thus there are no SO<sub>2</sub> or NO<sub>x</sub> permit limits or actual emissions.

As shown in Table 2, the actual NO<sub>x</sub>, PM<sub>10</sub>, and SO<sub>2</sub> emissions for the Quarry Crusher Engine (069) are below the 10 TPY threshold, and the engine will not be evaluated further. The actual SO<sub>2</sub> emissions for the Kiln (039) are below 10 TPY, so this pollutant will not be analyzed for the kiln. This analysis will focus on PM<sub>10</sub> and NO<sub>x</sub> emissions for the Kiln (039) and PM<sub>10</sub> emissions for the Clinker Cooler (040). The kiln is the primary source of visibility impairing pollutants including NO<sub>x</sub> and PM<sub>10</sub>. The clinker cooler is another significant source of PM<sub>10</sub> emissions.

## II. Source Controls

### Kiln (AIRS 039)

The GCC Pueblo kiln fires primarily low sulfur, high BTU coal from mines in Colorado. Coal specifications for 2018 are listed in Table 3. The kiln is also permitted to fires natural gas, tire-derived fuel (TDF), and many alternative, non-hazardous waste fuels. However, the kiln only uses natural gas for startup and primarily fires coal. When available, the kiln is fired with coal combined and some TDF which can reduce NO<sub>x</sub> emissions. The kiln is permitted to fire a maximum of 198,418 TPY of fuel (coal and TDF). There is a facility-wide limit of 381,373 MMBtu/yr of natural gas which is used for the finish mill heater and for kiln startup. APENs submitted for the kiln do not provide an exact heat content for the natural gas, but designate it as pipeline natural gas, which typically has a heat content around 1,020 MMBtu/MMscf. The APEN also does not list the sulfur content of the natural gas, but pipeline natural gas is extremely low in sulfur.

Table 3: Coal Specifications (2018 APEN)

	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Kiln	8,000-12,500	0.65	18

Table 4 depicts technical information for the GCC Pueblo kiln.

Table 4: Pueblo Kiln RP-eligible Emission Controls and Reduction (%)

	Portland Cement Kiln
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Placed in Service	2008
Description	Preheater/precalciner kiln with 5-stage, single string preheater
Air Pollution Control Equipment	SO <sub>2</sub> -Inherent Scrubbing of the Cement Process in the Kiln and the In-line Raw Mill  PM/PM <sub>10</sub> - 2 Baghouses (Main Kiln, Coal Mill)  NO <sub>x</sub> - Selective Non-Catalytic Reduction
Emissions Reduction (%)	SO <sub>2</sub> - 99.99% * PM / PM <sub>10</sub> - 99.99% / 99.99% ** NO <sub>x</sub> - 53.6% ***

\*SO<sub>2</sub> reductions based on actual SO<sub>2</sub> emissions measured by CEMS and input sulfur content. The sulfur input to the kiln is estimated as (Annual tons coal \* Weight fraction of sulfur in coal) + (Annual tons of raw meal \* Weight fraction of sulfur in raw meal).

\*\*PM/PM<sub>10</sub> reductions based on stack tests.

\*\*\*NO<sub>x</sub> reductions are based on the uncontrolled AP-42 emission factor for a preheater/precalciner kiln (4.2 lb/ton of clinker) compared to the 2016-2018 average 30-day emission rate (1.95 lb/ton of clinker). The Pueblo kiln was built with an SNCR, so the Division cannot compare pre-control and post-control emissions.

The source has not announced a closure date for the kiln, so the Division will assume a remaining useful life of 20 years for any control cost analysis.

#### **Clinker Cooler (AIRS 040)**

The clinker cooler employs a baghouse to control particulate emissions. Baghouses are typically a top-tier control for PM.

### **III. Reasonable Progress Evaluation of GCC Pueblo plant**

#### ***a. SO<sub>2</sub>***

SO<sub>2</sub> emissions for the Kiln (039) are below the 10 TPY de minimis threshold and thus were not evaluated for SO<sub>2</sub> controls.

#### ***b. Filterable Particulate Matter (PM<sub>10</sub>)***

##### **Step 1: Identify All Available Technologies**

#### **Kiln (AIRS 039)**

Filterable and condensable PM<sub>10</sub> emissions from the kiln are greater than the 10 TPY threshold. As noted earlier, the GCC Pueblo kiln is the newest unit in Colorado and the only kiln with a condensable PM<sub>10</sub> limit. Filterable PM emissions are solid and liquid particles at stack conditions and are typically controlled with fabric filter baghouses or electrostatic precipitators (ESPs). Filterable PM emissions can be measured using EPA reference methods that capture by the particulate matter in the filter segment of a sampling train. Over 99.9% of these filterable emissions are captured by the existing fabric filter baghouse. Electrostatic precipitators are the primary alternative for reducing filterable PM and can achieve over 99.9% control efficiency on some sources. However, the high resistivity of cement kiln dust



makes them less effective than baghouses for controlling PM emissions from Portland cement kilns.<sup>1</sup>

Condensable PM emissions are vapors at stack conditions, but quickly condense after exiting the stack. The condensable emissions consist of organics (VOCs) and inorganics (primarily ammonium salts). The 2012 permit modification request from GCC states that the organic content in the raw materials is less than 1% and the volatile content of the coal is also low, which suggests that most of the condensable PM emissions from the kiln are inorganic ammonium salts. These inorganic ammonium salts form when excess ammonia from the SNCR, known as ammonia slip, reacts with chlorides and sulfates from the raw materials and coal. The most effective control methods for condensable PM emissions are limiting the available supply of ammonia, chlorides, sulfates, and other compounds that can form PM. Reducing ammonia slip limits the available ammonia to form these salts. The chloride content of the raw materials is limited to avoid alkali chloride deposits building up in the kiln preheater and chloride levels are typically low in coal. Firing low sulfur coal reduces sulfur input to the kiln, but most SO<sub>2</sub> emissions result from pyrite and other sulfur contaminants in the limestone, which vary depending on the limestone source. The cement production process is very effective at scrubbing SO<sub>2</sub> unless high pyrite levels limit this inherent scrubbing process. Since the GCC Pueblo kiln has very low SO<sub>2</sub> emissions without the use of a scrubber, the Division concludes that the raw materials have very low pyrite levels. Therefore, the most effective way to minimize condensable PM emissions is to limit ammonia slip. The in-line raw mill not only provides raw materials for the kiln, it also acts as a scrubber to further reduce ammonia emissions. When the raw mill is operating, GCC operates the SNCR to comply with the NO<sub>x</sub> permit limit. The raw mill operates continuously when the kiln is operating, except for downtime associated with the maintenance or malfunctions of the mill. If the raw mill is shut down for maintenance or due to a malfunction, the SNCR stops injecting ammonia into the kiln to avoid a spike in ammonia emissions that could lead to a visible plume that exceeds the opacity limit for the kiln.

The baghouse on the GCC Pueblo kiln is a top tier control for filterable PM emissions, and the facility effectively minimizes condensable PM emissions by limiting ammonia slip from the SNCR and using fuel and raw materials with low sulfate and chloride levels. The Division has not identified any additional controls or work practices that would improve upon the existing filterable and condensable PM controls.

### **Clinker Cooler (AIRS 040)**

The clinker cooler uses fans to circulate cool, ambient air over the hot clinker exiting the kiln. As the ambient air absorbs heat it becomes hotter and this hot air is returned to the kiln which improves the kiln's energy efficiency by reducing the amount of fuel that needs to be fired to heat the kiln. Cooler air from later stages of the clinker cooler passes through a baghouse for PM control before exiting a separate stack. GCC reports emissions based on the results of a stack tests which are below a BACT limit of 0.01 gr/dscf (grains per dry standard cubic foot). GCC reports PM control efficiency of 99.99% on its APEN submittals to the Division, which is in line with baghouse control efficiencies for other processes. EPA notes that clinker cooler are typically controlled using fabric filter baghouses, though it provides emission factors for other potential controls such as Electrostatic Precipitators (ESPs).<sup>2</sup> Although ESPs may provide similar control efficiencies to baghouses, ESPs often require

<sup>1</sup> North Carolina DEQ. "Carolinas Cement Company: Control Technology Analysis." Page 10 of 102. April 2008.

<sup>2</sup> EPA. AP-42 Emission Factor for Portland Cement Manufacturing, pages 7 and 14. January 1995.



shutdowns for maintenance, whereas baghouses can be maintained while the cooler is operating. Because the existing baghouse achieves high control efficiency and can be maintained during operation, the Division has determined that the GCC Pueblo clinker cooler already has top tier PM controls and no new particulate control measures have been identified that would significantly upon the existing fabric filter baghouse.

#### **Step 2: Eliminate Technically Infeasible Options**

##### **Kiln (AIRS 039)**

The Division has determined that the currently operating PM/PM<sub>10</sub> controls on the kiln perform better than any of the identified control technologies. Therefore, there are no remaining technically feasible options other than the existing controls in operation for the GCC Pueblo kiln.

##### **Clinker Cooler (AIRS 040)**

The Division has determined that the currently operating PM/PM<sub>10</sub> controls on the clinker cooler perform better than any of the identified control technologies. Therefore, there are no remaining technically feasible options other than the existing controls in operation for the GCC Pueblo clinker cooler.

#### **Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

##### **Kiln (AIRS 039)**

Filterable PM<sub>10</sub> emissions from the GCC kiln are reported based on a baghouse loading factor, but stack testing indicates that actual filterable emissions are much lower than the estimates based on the baghouse loading factor. Condensable PM<sub>10</sub> emissions are reported based on emission factors determined through stack testing and approved by the Division. GCC reports the baghouses achieve 99.99% control efficiency on the APENs submitted to the Division, and the Division has not identified other control options with higher control efficiencies.

##### **Clinker Cooler (AIRS 040)**

Filterable PM<sub>10</sub> emissions from the GCC clinker cooler are reported based on a baghouse loading factor, but stack testing indicates that actual filterable emissions are much lower than the estimates based on the baghouse loading factor. GCC reports the baghouses achieve 99.99% control efficiency on the APENs submitted to the Division, and the Division has not identified other control options with higher control efficiencies.

#### **Step 4: Evaluate Factors and Present Determination**

##### **Factor 1: Cost of Compliance**

##### **Kiln (AIRS 039)**

There are no associated costs of compliance since no options other than continuing to operate the existing PM controls on the kiln are considered technically feasible.

##### **Clinker Cooler (AIRS 040)**

There are no associated costs of compliance since no options other than continuing to operate the existing PM controls on the clinker cooler are considered technically feasible.

##### **Factor 2: Time Necessary for Compliance**

##### **Kiln (AIRS 039)**

There is no additional time required for compliance since no options other than continuing to operate the existing PM controls on the kiln are considered technically feasible.



**Clinker Cooler (AIRS 040)**

There is no additional time required for compliance since no options other than continuing to operate the existing PM controls on the clinker cooler are considered technically feasible

**Factor 3: Energy and Non-Air Quality Impacts**

**Kiln (AIRS 039)**

There are no specific energy and non-air quality impacts associated with the continued operation of the particulate controls on the kiln.

**Clinker Cooler (AIRS 040)**

There are no specific energy and non-air quality impacts associated with the continued operation of the particulate controls on the clinker cooler.

**Factor 4: Remaining Useful Life**

**Kiln (AIRS 039)**

GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry. Therefore, the Division assumes that the kiln will remain in operation for at least 20 years. Because no additional control options are considered technically feasible, remaining useful life does not impact cost estimates for additional controls.

**Clinker Cooler (AIRS 040)**

GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry. Therefore, the Division assumes that the clinker cooler will remain in operation for at least 20 years. Because no additional control options are considered technically feasible, remaining useful life does not impact cost estimates for additional controls.

**Determinations**

**Kiln (AIRS 039)**

Based upon its consideration of the four factors summarized herein and detailed in Appendix C, the Division recommends that RP for PM<sub>10</sub> is the following:

- 1) The following existing PM<sub>10</sub> emission limits shall remain in effect for this planning period:  
Kiln: 36.01 TPY (filterable, 12-month rolling average)  
293.56 TPY (condensable, 12-month rolling average)

The state assumes that the RP emission limits can be achieved through continued operation and maintenance of the existing fabric filter baghouse, good combustion practices, and good operation of the SNCR to minimize NO<sub>x</sub> and excess ammonia emissions. The Division has determined that these limits are achievable without additional capital investment through the four-factor analysis.

**Clinker Cooler (AIRS 040)**

Based upon its consideration of the four factors summarized herein and detailed in Appendix C, the Division recommends that RP for PM<sub>10</sub> is the following:

- 1) The following existing PM<sub>10</sub> emission limit shall remain in effect for this planning period:  
Clinker Cooler: 33.92 TPY (12-month rolling average)



The state assumes that the RP emission limits can be achieved through continued operation and maintenance of the existing fabric filter baghouse. The Division has determined that this limit is achievable without additional capital investment through the four-factor analysis.

**c. Nitrogen Oxides (NO<sub>x</sub>)**

**Step 1: Identify All Available Technologies**

**Kiln (AIRS 039)**

As noted earlier, the GCC Pueblo facility was not evaluated during the first round of Regional Haze because it had undergone a pre-construction PSD review and was recently constructed with many technologies to reduce NO<sub>x</sub> including: an energy efficient multi-stage preheater, low-NO<sub>x</sub> calciner, low-NO<sub>x</sub> Burners (LNBs) with indirect firing, staged combustion (SCC), and a Selective Non-Catalytic Reduction (SNCR) unit. Table 5 shows the current limits and actual emissions for the 2016-2018 baseline period. As shown, the kiln is in compliance with the 12-month total and lb/ton of clinker limits. As shown in Table 4, the GCC Pueblo kiln achieves approximately 53.6% lower NO<sub>x</sub> emissions than a baseline uncontrolled preheater/precalciner kiln using the NO<sub>x</sub> controls listed above, as well as firing tire-derived fuel (TDF), when available. Unlike the CEMEX Lyons and Holcim Florence kilns, the GCC Pueblo kiln does not currently have a 30-day rolling average NO<sub>x</sub> limit. The Division will discuss potential emission limit changes later in this analysis.

**Table 5: Kiln Limits vs. Actual Emissions**

	Limit	2016-2018 Actual Average [Min - Max]
12-Month Rolling Total (TPY)	1,100.0	915.18 [816.6 - 996.7]
12-Month Rolling Average (lb/ton of clinker)	2.32	1.97 [1.82 - 2.11]
30-day Rolling Average (lb/ton of clinker)	N/A	1.95 [1.61 - 2.70]

The Division reviewed EPA's RACT/BACT/LAER Clearinghouse (RBLC) for similar Portland cement kilns for the most recent 20 years and the EPA Menu of Control Measures for additional or improved potential control options. Most of the recently permitted kilns are multi-stage preheater/precalciner designs that are comparable to the GCC Pueblo kiln. However, cement kiln emissions are highly dependent on fuel and raw material composition, in addition to the general kiln design. The RBLC determinations provide an indication of the achievable emission rates at Portland cement kilns that are subject to the latest NSPS. Based on the startup date for the GCC Pueblo kiln, it is not subject to the NSPS limit of 1.50 lb/ton of clinker. The lowest emission permitted emission rate listed in the RBLC was the Universal Cement Plant in Illinois which was permitted in 2010 at 1.2 lb/ton of clinker. Illinois EPA deemed this to meet LAER and was achievable using a combination of staged combustion and SNCR. This facility was never constructed. The CEMEX North Brooksville Kiln 3 was permitted in 2007 at 1.5 lb/ton of clinker with SNCR or SCR or a combination of these two. The permit was withdrawn and this kiln was never constructed. Other determinations range from 1.5 lb/ton to 2.65 lb/ton of clinker and utilize SNCR, often combined with indirect firing, low-NO<sub>x</sub> burners, and staged combustion, all of which are utilized in the GCC Pueblo kiln.



The following kiln NO<sub>x</sub> controls were considered, if technically feasible, for this planning period:

- Fuel Substitution - Firing Tire-Derived Fuel (TDF)
- Selective Non-Catalytic Reduction + Low- NO<sub>x</sub> Burners (SNCR + LNB)
- Staged and Controlled Combustion (SCC)
- Selective Catalytic Reduction (SCR)

## Step 2: Eliminate Technically Infeasible Options

### **Kiln (AIRS 039)**

**Fuel Substitution:** Fuel substitution for Portland cement kilns involves firing a combination of fossil fuels and alternative fuels, such as non-hazardous waste and tire-derived fuel (TDF). In principal, converting a cement kiln to full natural gas combustion would significantly reduce SO<sub>2</sub> and PM<sub>10</sub> emissions, but would not significantly reduce NO<sub>x</sub> emissions.<sup>3</sup> However, a natural gas flame in the main kiln burner may not sufficiently dissipate heat which can reduce clinker production and may require raw meal reformulation to maintain product quality.<sup>4</sup> The lower heat transfer of a natural gas flame in the main kiln can also lead to higher temperatures that increase thermal NO<sub>x</sub> production.<sup>5</sup> Although few kilns use natural gas as the primary fuel, many kilns, including the GCC Pueblo facility, fire natural gas at startup to minimize emissions while heating up the kiln. Discussions with other Colorado kiln operators confirmed that operating a kiln entirely on natural gas may require extensive modifications to the kiln design and controls and result in lower production capacity. When used correctly, alternative fuels with high energy content (Btu/lb), such as TDF, can help safely dispose of waste tires and reduce NO<sub>x</sub> emissions from the kiln. However, the kiln operator needs to maintain proper combustion conditions to avoid emissions increases from firing TDF. GCC is currently firing the kiln with low sulfur coal, as indicated in Table 3, natural gas for startup, and TDF, when available.

In 2002, CEMEX conducted a stack test with the long-dry kiln firing a combination of coal and TDF. The stack tests on this long-dry kiln suggested 24.4% reductions in NO<sub>x</sub> emissions from firing TDF without exceeding the standards for any other criteria pollutants or hazardous air pollutants.<sup>6</sup> However, the reductions are highly kiln dependent and also dependent on the fuel being replaced. Simulations for fuel switching at Lafarge's Brookfield cement plant in Nova Scotia indicated that switching from a 100% blend of high sulfur coal and pet coke (50-50 blend, 3.5% overall weight % sulfur) to 30% TDF and 70% coal/pet coke blend would reduce fuel NO<sub>x</sub> by 23%.<sup>7</sup> In contrast, EPA expects that firing TDF can reduce NO<sub>x</sub> emissions by 33% on average, but in rare cases kilns may see NO<sub>x</sub> increases around 20% as well as increases of other criteria pollutants. Overall, the Division expects that firing TDF can reduce NO<sub>x</sub> emissions.

GCC is already permitted to fire TDF and utilizes the fuel when available. Colorado has the largest waste tire piles, known as monofills, in the country and combusting them at high heat

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<sup>3</sup> EPA. "Alternative Control Techniques Document Update - NO<sub>x</sub> Emissions from New Cement Kilns." Page 44 of 129. November 2007.

<sup>4</sup> IEEE Cement Industry Technical Conference. "From coal to natural gas: Its impact on kiln production, Clinker quality and emissions." 2013.

<sup>5</sup> EPA. "Alternative Control Techniques Document Update - NO<sub>x</sub> Emissions from New Cement Kilns" November 2007.

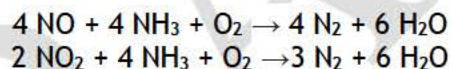
<sup>6</sup> BART Analysis for CEMEX Lyons Cement Plant. Page 21

<sup>7</sup> Dalhousie University. "Use of scrap tires as an alternative fuel source at the Lafarge cement kiln, Brookfield, Nova Scotia, Canada" Page 23. July 21, 2015.



in a cement kiln not only reduces NO<sub>x</sub> emissions from the kiln, it can also reduce the likelihood of large uncontrolled, monofill fires that release thick black clouds of smoke due to poor combustion conditions.<sup>8</sup> In order to use these tires on a consistent basis, cement manufacturers need a nearby monofill and may require government incentives to cover the cost of shredding the tires and transporting them to the facility, especially if the monofill is far from the cement plant. In recent years, GCC has struggled to identify a large, consistent supply of tires near the Pueblo area, and funding for Colorado's waste tire program has varied from year to year. Due to these issues, the Division considers it infeasible to mandate a minimum amount of annual TDF usage considering that GG is already permitted to use a significant amount of TDF as fuel. As more TDF becomes available, GCC will use more TDF. Therefore, a limit requiring a certain amount of TDF is not necessary. The Division will continue to work with GCC to evaluate the facility's future use of TDF and look for opportunities to reduce kiln emissions and Colorado's large stockpile of waste tires. Since TDF usage is currently permitted and utilized, when available, the Division will not analyze this option further.

**SNCR:** Fuel substitution, which is discussed above, affects the combustion process, while SNCR and SCR are post-combustion controls that treat the combustion products. Both controls inject an ammonia or urea reagent into the flue gas to convert NO<sub>x</sub> to molecular nitrogen (N<sub>2</sub>). These reactions require higher temperatures in an SNCR (1,600 to 2,000°F), compared to SCR (450 to 800°F), and provided lower control efficiency. SNCR systems typically have lower capital costs than an SCR, but the operating costs are higher due to high reagent use. SNCR design requirements and performance are discussed in more detail below.



Above this temperature range, the NH<sub>3</sub> is oxidized to NO<sub>x</sub>, thereby increasing NO<sub>x</sub> emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH<sub>3</sub> may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH<sub>3</sub> could be delivered to the kiln system through the use of anhydrous NH<sub>3</sub>, or an aqueous solution of ammonium hydroxide [NH<sub>3</sub>(aq)] or urea [CO(NH<sub>2</sub>)<sub>2</sub>]. A concern about application of SNCR technology is the breakthrough of unreacted NH<sub>3</sub> as "ammonia slip" and its subsequent reaction in the atmosphere with SO<sub>2</sub>, sulfur trioxide (SO<sub>3</sub>), hydrogen chloride (HCl) and/or chlorine (Cl<sub>2</sub>) to form a detached plume of PM<sub>10</sub>-PM<sub>2.5</sub>. In addition to reacting with SO<sub>x</sub> and chloride emissions from the kiln, the unreacted ammonia could react with NO<sub>x</sub> or SO<sub>x</sub> from other sources to form visibility impairing ammonium nitrate or ammonium sulfate, respectively. As discussed earlier, the in-line raw mill at the GCC Pueblo kiln is an important part of the emission control system that helps minimize unreacted ammonia emissions and the raw mill is operating when the kiln is operating, except for planned weekly mill maintenance and unexpected mill malfunctions.

The existing NO<sub>x</sub> controls on the GCC Pueblo kiln, which include an SNCR, currently achieve average annual NO<sub>x</sub> emissions of 1.97 lb/ton of clinker, which represents a 53% reduction in NO<sub>x</sub> emissions, compared to an uncontrolled preheater/precalciner kiln. This agrees with EPA's SNCR performance data which indicates that the technology can achieve NO<sub>x</sub> reductions

<sup>8</sup> Booth, Michael. "Colorado's tire dumps were supposed to be gone by now. They grew instead." Colorado Sun. January 19, 2021.



of 20 - 90%, with 50% as a reasonable long-term reduction.<sup>9</sup> It's important to note that achieving high NO<sub>x</sub> (>60%) control efficiencies with an SNCR often results in high ammonia slip, as discussed in EPA's ACT for NO<sub>x</sub> emissions from cement kilns.<sup>10</sup> As explained in the PM section above, ammonia slip from the SNCR can react with chlorides and sulfates from the raw materials and coal to form condensable PM emissions. In order to minimize both NO<sub>x</sub> and condensable PM emissions, the SNCR is operated to limit excess ammonia injection and the in-line raw mill acts as a scrubber to further reduce ammonia emissions, when the mill is operating. If the raw mill is shut down for maintenance or due to a malfunction, the SNCR temporarily stops to avoid a spike in ammonia emissions that could lead to a visible plume that exceeds the opacity limit for the kiln. When the raw mill is restarted, the SNCR operates at higher ammonia injection rates to compensate for the higher NO<sub>x</sub> emissions during the raw mill downtime, and to comply with the 1,100 TPY and 2.32 lb/ton of clinker limits. As discussed earlier, the SNCR on the GCC Pueblo kiln operates around 95% of the hours in a week, but is permitted on an "as-needed" basis to allow for the 8-hour weekly maintenance of the in-line raw mill. The kiln was initially permitted with a minimum required uptime for the SNCR, but modeling indicated that the increased ammonia emissions from the kiln would require a higher condensable PM limit. The permit was revised to reflect the "as-needed" SNCR operation to avoid a large increase in PM emissions for a limited reduction in NO<sub>x</sub> emissions. The Division still believes that requiring GCC Pueblo to operate the SNCR on a continuous basis without an allowance for maintenance of the in-line raw mill would increase ammonia slip and visibility-impairing condensable PM emissions. Given that the GCC Pueblo plant is located in an ozone attainment area and less than 10 miles from the populated Pueblo community, the Division does not believe the potential NO<sub>x</sub> reduction is a valid trade-off for likely increases in ammonia emissions. Therefore, it is not recommending a change to continuous SNCR operations.

The Division and GCC have not identified any potential upgrades to the existing SNCR that would significantly improve its performance. The Division will continue to monitor the long-term performance of the SNCR and will work with GCC to ensure that the kiln achieves the maximum NO<sub>x</sub> control at a reasonable cost without significant increases in PM or other emissions. SNCR changes will not be analyzed in further detail.

**SNCR + LNB:** Low-NO<sub>x</sub> burners (LNB) are designed to create a multi-stage combustion process with less excess oxygen. LNBs create a fuel-rich primary combustion zone where the low oxygen levels result molecular nitrogen (N<sub>2</sub>) formation, rather than NO<sub>x</sub>, from nitrogen in the combustion air and fuel-bound nitrogen. The GCC kiln currently employs low-NO<sub>x</sub> burners with the SNCR discussed above to achieve 53% NO<sub>x</sub> reductions. The Division has not identified additional upgrades to the existing LNBs that would achieve additional NO<sub>x</sub> reductions.

**SCR:** SCR systems are the most widely used post-combustion NO<sub>x</sub> control technology for coal-fired and natural gas-fired boilers. However, the technology has seen very little use at US cement kilns. In SCR systems, vaporized ammonia (NH<sub>3</sub>) injected into the flue gas stream acts as a reducing agent when passed over an appropriate amount of catalyst. The NO<sub>x</sub> and ammonia react to form nitrogen and water vapor, as described in the equations in the SNCR section. The principal is similar to SNCR, which is currently installed at the GCC Pueblo kiln, but the SCR catalyst reduces the required flue gas temperature necessary for the NO<sub>x</sub>

<sup>9</sup> EPA. National Emissions Standard for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry - [Cost Environmental Impact Data](#). August 6, 2010.

<sup>10</sup> EPA. "Alternative Control Techniques Document Update - NO<sub>x</sub> Emissions from New Cement Kilns." Page 17 of 129. November 2007.



reducing reaction. An optimized SCR design will provide the maximum level of NO<sub>x</sub> reduction while maintaining low ammonia slip that could harm health and impair visibility. Detached plumes are possible with SCR, but less common than with SNCR.

EPA's ACT for NO<sub>x</sub> emissions from cement kilns discusses SCR control for cement kilns. The document notes the SCR operating range depends on the catalyst material, and can range from 450°F to 800°F for base metal catalysts, to over 1,100°F for precious metal catalysts, though these are typically much more expensive. There are numerous challenges to operating an SCR on a cement kiln, including plugging and erosion of the catalyst caused by the high dust produced in the kiln. According to Benson<sup>11</sup>, alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (See also Nicosia *et al.*, 2008, and Strege *et al.*, 2008). Calcium, in the form of limestone, is a staple of cement production, though sodium, potassium, and magnesium levels are tightly controlled in the raw meal to prevent swelling or cracking of the concrete. Also, alkalies and sulfur can potentially poison the catalyst.<sup>12</sup> The low levels of sulfur in the raw materials and inherent sulfur control of the cement process significantly reduces sulfur levels, but alkali levels could potentially impact the catalyst.

The two biggest remaining concerns for a potential SCR system at the GCC Pueblo facility are dust and site-specific design requirements. SCR systems can often be installed on coal-fired boilers in a "high dust" configuration, upstream of the particulate control device. However, this may not be feasible for cement kilns, including the GCC Pueblo kiln, due to the potential for catalyst plugging and erosion caused by the very high dust levels in a kiln. Therefore, the SCR would need to be installed in a "low dust" configuration, downstream of the baghouse. Unfortunately, the post-baghouse flue gas temperature has dropped below the ideal range for SCR operation and it would require reheating with a duct burner or heat exchanger using natural gas or coal. This reheating increases upfront capital costs for the system, ongoing operating and maintenance costs for fuel and burner/heat exchanger maintenance, and results in additional NO<sub>x</sub> emissions that increase inlet NO<sub>x</sub> levels to the SCR system. Lastly, at the time of the BART analysis, three cement kilns in Europe had installed SCR systems. Two were newer preheater kilns and the third was a smaller, traveling grate kiln. Although these kilns could achieve 80-90% NO<sub>x</sub> reductions, it was unclear how well these results would translate to US cement kilns. As noted in the CEMEX BART analysis, the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available.<sup>13</sup> A search of the RBLC indicates that the CEMEX North Brooksville Kiln #3 selected SNCR, SCR, or a combination of the two technologies to meet BACT for NO<sub>x</sub> control. However, this permit was withdrawn, and this kiln was never constructed. Due to a lack of any commercially available SCR units on US cement kilns, the Division concluded that SCR was not technically feasible for retrofit on existing cement kilns at that time.

Since the CEMEX BART analysis was conducted, there has been a single US cement kiln, the Lafarge Joppa Kiln 1 in Illinois that installed an SCR for NO<sub>x</sub> Control. Joppa Kiln 1 is a long dry kiln with LNB and a hot electrostatic precipitator (ESP) for PM control. The SCR is installed downstream of the ESP in a "low dust" arrangement. This SCR was required as part of 2010

<sup>11</sup> Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005).

<sup>12</sup> Strege, J. *et al.*, "SCR deactivation in a full-scale co-fired utility boiler, Fuel 87" (2008)

<sup>13</sup> Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)



consent decree (CD) with Lafarge that covered kilns at 13 facilities in 13 states.<sup>14</sup> Joppa Kiln 1 was the only kiln required to install an SCR. Lafarge was required to conduct a 12-month optimization study to determine the kiln's emission limit. The emission limit was ultimately set at 3.21 lb/ton of clinker using the formula prescribed in the consent decree:  $\text{Limit} = \mu + 1.645\sigma$ , where  $\mu$  is the mean of the 30-day rolling averages during the 12-month optimization period and  $\sigma$  is the standard deviation of the 30-day rolling averages. According to the Final Demonstration Report for the SCR, the mean was 1.99 lb/ton of clinker and the standard deviation was 0.75 lb/ton of clinker, resulting in an 80% reduction in NO<sub>x</sub> compared to the baseline levels.<sup>15</sup> The average 30-day emission rate from Joppa Kiln 1 (1.99 lb/ton of clinker) using LNB + SCR is slightly higher than the current emissions from GCC Pueblo (1.95 lb/ton of clinker) with LNB + SNCR. Also, the NO<sub>x</sub> emissions from Joppa Kiln 1 have much greater variability, as indicated by the standard deviation of 0.75 lb/ton of clinker, which is about 3.5 times larger than GCC Pueblo's standard deviation of 0.21 lb/ton of clinker. In addition, cost information for the Joppa SCR is not publicly available, so it's not possible to compare the cost effectiveness to the existing SNCR at GCC Pueblo.

Since the Joppa consent decree in January 2011, EPA has issued nine consent decrees against cement manufacturers, as shown in Table 6 below. This includes the CEMEX Lyons facility in Colorado. All of the facilities were required to install an SNCR to comply with NO<sub>x</sub> limits, except for Essroc Logansport Kiln 1 and Kiln 2 in Indiana, which are both long wet kilns that are not comparable to GCC Pueblo. Both Logansport kilns were required to conduct 4-month SCR pilot studies.<sup>16</sup> If the pilots were deemed successful, the kilns would operate the SCR going forward based on a NO<sub>x</sub> limit established during the pilot studies. If the studies were deemed unsuccessful, the kilns would install SNCR with a NO<sub>x</sub> limit determined by EPA. "Success" for the SCR pilot studies included reducing NO<sub>x</sub> by at least 80% while maintaining ammonia slip below 10 ppm without negatively impacting product quality or kiln reliability. Essroc completed these SCR studies and submitted the report to EPA, but EPA rejected them. Essroc filed for dispute resolution and, as a result, EPA required Essroc to run a second SCR study and submit the performance reports to EPA. Prior to the start of the second SCR study, EPA required Logansport Kiln 1 and Kiln 2 to establish tighter emission limits, but neither kiln was required to permanently install an SCR. Ultimately, EPA, Essroc, and the State of Indiana required Logansport Kiln 2 to install a water injection system with a NO<sub>x</sub> limit of 4.75 lb/ton of clinker, on a 30-day rolling average. Logansport Kiln 1 was required to install a water injection system and an SNCR, and conduct a study to establish a NO<sub>x</sub> emission limit that is no less stringent than 4.75 lb/ton of clinker. The Division was unable to obtain a copy of either the initial or second SCR pilot studies, but has concluded that neither Kiln 1 nor Kiln 2 is currently operating an SCR. This leaves the Joppa kiln as the only US cement kiln still operating an SCR for NO<sub>x</sub> control. Table 9 demonstrates that the limit of 1.85 lb/ton of clinker imposed by the CEMEX Lyons consent decree matched the lowest emission limit set by consent decree up to April 2013. Although GCC's annual limit of 2.32 lb/ton of clinker is higher than CEMEX's limit, the current requirements for the facilities are very different: the GCC Pueblo facility is located in an attainment area whereas CEMEX is an ozone nonattainment area, GCC's SNCR was installed for BACT not due to a consent decree, and CEMEX is not subject to condensable PM or ammonia slip limits, both of which allows CEMEX to operate at higher ammonia injection rates to achieve greater control efficiency. Other than the Lafarge Joppa kiln 1 in Illinois, no US cement kilns have installed and continue to

<sup>14</sup> EPA. Consent Decree: Lafarge North America, Inc, Lafarge Midwest, Inc, and Lafarge Building Materials, Inc. January 2010.

<sup>15</sup> LAFARGE - U.S. EPA Consent Decree Final Demonstration Report, Joppa Kiln 1. April 2015.

<sup>16</sup> EPA. Consent Decree: Essroc Cement Corp. December 2011.



operate an SCR for NO<sub>x</sub> control based on a consent decree. As discussed earlier, the Joppa kiln has a much higher emission limit and more NO<sub>x</sub> emission variability than nearly all recent consent decrees, including GCC Pueblo. All of the other consent decree limits are based on SNCR controls, as shown in Table 6.

**Table 6: EPA Cement Manufacturer Consent Decrees after January 2010**

Company Name	CD Date	# of Facilities Included in CD	# of Kilns Included in CD	NO <sub>x</sub> Limit (Control Tech)
CEMEX Fairborn	Feb 2011	1	1	1.85 lb/ton (SNCR)
CalPortland	Dec 2011	1	1	2.5 lb/ton (SNCR)
Essroc (now Lehigh Cement)	Dec 2011	6	9	1.85 - 4.75 lb/ton (SNCR) *
CEMEX Lyons	Apr 2013	1	1	1.85 lb/ton (SNCR)
Ash Grove	June 2013	9	13	1.5 - 8 lb/ton (SNCR)
Holcim/St. Lawrence	July 2013	1	1	1.8 lb/ton (SNCR)
CEMEX	July 2016	5	7	1.5 - 5.3 lb/ton (SNCR)
Lonestar/Buzzi	Aug 2016	1	1	1.5 - 2.9 lb/ton (SNCR) **
Lehigh	Dec 2019	11	14	1.5 - 8.2 lb/ton (SNCR)

\* Essroc Logansport was required to conduct SCR pilot studies on Kilns 1 and 2. The pilot study reports were rejected by EPA and the source and EPA ultimately agreed to install water injection on both kilns. Kiln 1 was also required to install an SNCR. Both kilns have limits of 4.75 lb/ton of clinker.

\*\* The two emission rates at the Lonestar facility are for firing waste (1.5 lb/ton) and not firing waste (2.9 lb/ton).

The Division also reviewed the RBLC to look for instances where SCR has been approved. As discussed earlier, the CEMEX North Brooksville Kiln 3 in Florida was permitted in 2007 with SNCR, SCR, or a combination of the two, but the permit was withdrawn and the kiln was never built. The only LAER determination listed in the RBLC was the Universal Cement plant in Illinois that was permitted at 1.2 lb/ton of clinker using staged combustion and SNCR, not SCR. LAER determinations seek the lowest achievable emission rate without consideration of cost, a more stringent standard than the BACT determination for GCC Pueblo, and SCR has not been selected as LAER for NO<sub>x</sub> emissions from cement kilns. Under Regional Haze, states must consider cost of compliance when evaluating potential controls and the Division believes it is inappropriate to recommend essentially unproven technologies beyond LAER under Regional Haze.

The only existing US cement kiln with an operating SCR for NO<sub>x</sub> control, the Lafarge Joppa Kiln 1, has very little publicly available information, including costs. Based on the information available to the Division, this SCR is achieving 80% control efficiency, which is higher than the 53% control efficiency of the GCC Pueblo SNCR, but without additional cement kilns using SCR for NO<sub>x</sub> control it is unclear whether the technology could consistently achieve 80% control



efficiency at other facilities, such as GCC Pueblo. Although the Joppa Kiln 1 SCR must maintain an ammonia slip limit, it is not subject a condensable PM limit, which may allow for higher ammonia injection rates to achieve greater NO<sub>x</sub> reductions. SNCR technology has also been chosen over SCR under recent consent decrees, BACT, and LAER determinations. Given the limited potential NO<sub>x</sub> reductions, unknown cost, and lack of SCR installations on comparable preheater/precalciner kilns, the Division still considers SCR technology infeasible for cement kilns and it will not be analyzed further.

**Staged and Controlled Combustion (SCC):** EPA's ACT NO<sub>x</sub> Emissions from New Cement Kilns also discusses staged and controlled combustion control (SCC) for cement kilns. The document explains SCC as follows:

*SCC works by staging the introduction of fuel, combustion air, and feed material in a manner to minimize NO<sub>x</sub> formation and reduce NO<sub>x</sub> to nitrogen. NO<sub>x</sub> formed in the kiln's combustion zone is chemically reduced by maintaining a reducing atmosphere at the kiln feed end by firing fuel in this region. The reducing atmosphere is maintained in the calciner region by controlling combustion air such that the calcining fuel is first burned under reducing conditions to reduce NO<sub>x</sub> and then burned under oxidizing conditions to complete the combustion reaction. Controlling the introduction of raw meal allows for control of the calciner temperature. Through these mechanisms, both fuel NO<sub>x</sub> and thermal NO<sub>x</sub> are controlled. The combustion chamber allows for improved control over the introduction of tertiary air in the calciner region, which helps to promote the proper reducing environment for NO<sub>x</sub> control.*

SCC generally involves the staging of both air and fuel. Indirect firing is required for air staging, and LNB achieve one form of staged combustion. Both are employed at the GCC Pueblo kiln. The version of SCC discussed here combines indirect firing with LNB in the kiln with a combustion of a large portion of the fuel in a preheater/precalciner with a tertiary duct to return air from the clinker cooler to the preheater/precalciner. The Division has not identified additional upgrades to the staged combustion that would achieve additional NO<sub>x</sub> reductions.

### Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Table 7 summarizes each available technology and technical feasibility for NO<sub>x</sub> control on the GCC Pueblo kiln.

**Table 7: GCC Pueblo Kiln - NO<sub>x</sub> Technology Options and Technical Feasibility**

Technology	Emission Control Efficiency (%)	Technically Feasible? (Y = yes, N = no)
Baseline - LNB + SNCR + SCC (53% Control)	N/A	Y - installed
Fuel Substitution - Firing TDF	20 - 30%	Y - in use when available
SCR	N/A	N

The Division did not identify any additional controls that can achieve additional NO<sub>x</sub> reductions.

**Emission Limit Tightening:** Although the Division did not identify any additional NO<sub>x</sub> control measures, it also evaluated tightening emission limits for the GCC Pueblo kiln. GCC currently has a 12-month rolling average emission NO<sub>x</sub> limit of 2.32 lb/ton of clinker. The CEMEX Lyons and Holcim Florence kilns are subject to 30-day Rolling Average NO<sub>x</sub> limits, and the Division



considers this shorter averaging period helps reduce emission variability, in line with the goals of the Regional Haze program. As discussed earlier, the Division has determined that setting a higher SNCR uptime requirement would likely increase in ammonia and condensable PM emissions over the city of Pueblo, which is not a reasonable trade-off for the potential NO<sub>x</sub> reductions. Therefore, the 30-day emission limit should be based on 2016-2018 baseline emissions under the currently permitted “as-needed” SNCR operating requirement. As shown in Table 5, the 30-day rolling averages for the GCC Pueblo kiln range from 1.61 - 2.70 lb/ton of clinker. This range is much larger than the 12-month rolling averages which range from 1.82 - 2.11 lb/ton of clinker. To account for the emission variability from cement kilns, the Division set RP limits for the Holcim Florence cement kiln based on the 99<sup>th</sup> percentile of the 30-day rolling averages, during the first Regional Haze planning period. Using this same metric would result in a NO<sub>x</sub> limit of 2.65 lb/ton of clinker for the GCC Pueblo kiln. This emission rate is less than 2% lower than the maximum 30-day rolling average of 2.70 lb/ton of clinker. The Division believes this slightly lower emission limit would not provide meaningful emission reductions. Therefore, the Division considers a 30-day rolling average limit of 2.70 lb/ton of clinker to be appropriate. Although this emission rate is higher than the current annual limit of 2.32 lb/ton of clinker, the Division believes this higher emission rate allows the facility to properly maintain the in-line raw mill which can help avoid large increase in condensable PM emissions. Additionally, without additional control options or a consistent supply of TDF, GCC would likely need to increase ammonia injection rates to achieve greater NO<sub>x</sub> reductions. As discussed in the SNCR analysis above, higher ammonia injection rates can provide higher NO<sub>x</sub> control efficiency, but the side effect is that the increased ammonia slip can result in a detached plume of sulfate, chloride, or nitrate particulates that impair visibility. Thus, the Division recommends a 30-day NO<sub>x</sub> limit of 2.70 lb/ton and retaining the annual limit of 1,100 TPY. The facility has recently completed upgrades to increase clinker production and as the facility reaches maximum clinker production, the kiln will need to decrease its 12-month rolling average NO<sub>x</sub> emissions from 1.97 lb/ton of clinker to approximately 1.87 lb/ton of clinker to remain within the 1,100 TPY limit. The Division will continue working with GCC to identify opportunities to reduce NO<sub>x</sub> emissions without leading to significant increases in other pollutants.

#### **Step 4: Evaluate Factors and Present Determination**

##### **Factor 1: Cost of Compliance**

There are no associated costs of compliance since no options other than continuing proper operation of the kiln and the existing LNB + SNCR units are considered technically feasible and cost effective.

##### **Factor 2: Time Necessary for Compliance**

There is no additional time required for compliance since no options other than continuing proper operation of the kiln and the existing LNB + SNCR units are considered technically feasible and cost effective.

##### **Factor 3: Energy and Non-Air Quality Impacts**

There are no additional energy and non-air quality impacts associated with the continued proper operation of the kiln and LNB+SNCR units on the GCC Pueblo kiln.

##### **Factor 4: Remaining Useful Life**

GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry. Therefore, the Division assumes that the kiln will remain in operation for at least 20 years.



Because no additional control options are considered technically feasible and cost effective, remaining useful life does not impact cost estimates for additional controls.

#### Determinations

Upgrades to the existing NO<sub>x</sub> control system were evaluated, and the state has determined that meaningful upgrades to the system are not available. Because the kiln will remain in operation for 20 years or more, the Division also evaluated emission limit tightening. The kiln is currently subject to a 12-month rolling average lb/ton of clinker limit, whereas the CEMEX Lyons kiln and Holcim Florence kiln are subject to 30-day rolling average limits. The Division has determined that the existing 12-month rolling average limits are set at an appropriate level, and a new 30-day rolling average limit is appropriate to reduce short-term emission variability. This new 30-day rolling average will ensure the facility continues operating the SNCR as much as practicable while allowing the facility to properly maintain the in-line raw mill, which limits excess ammonia emissions that could lead to excessive condensable PM emissions or visible plumes. These emission limits avoid trading a slight NO<sub>x</sub> decrease for an increase in other pollutants.

Based upon its consideration of the four factors summarized herein and detailed in Appendix C, the Division recommends that NO<sub>x</sub> RP is complying with the following emission rate and annual limits:

- 1) The following NO<sub>x</sub> emission limits shall remain in effect for this planning period:

Kiln: 2.70 lb/ton of clinker (30-day rolling average)  
2.32 lb/ton of clinker (12-month rolling average)  
1,100.0 TPY (12-month rolling average)

The state assumes that the RP emission limits can be achieved through continued proper operation and maintenance of the kiln, including the LNB and SNCR controls. The Division has determined that these emission limits are achievable without additional capital investment through the four-factor analysis.