



08/06/2026

Jonah Ross
Howmet Aerospace Inc.
1600 Harvard Ave
Cleveland, OH 44105

RE: DRAFT AIR POLLUTION PERMIT-TO-INSTALL

Facility ID: 1318170314
Permit Number: P0140885
Permit Type: Administrative Modification
County: Cuyahoga

No	TOXIC REVIEW
No	PSD
No	SYNTHETIC MINOR TO AVOID MAJOR NSR
No	CEMS
Yes	MACT/GACT
Yes	NSPS
No	NESHAPS
No	NETTING
No	MAJOR NON-ATTAINMENT
No	MODELING SUBMITTED
No	MAJOR GHG
No	SYNTHETIC MINOR TO AVOID MAJOR GHG

Dear Permit Holder:

A draft of the Ohio Administrative Code (OAC) Chapter 3745-31 Air Pollution Permit-to-Install for the referenced facility has been issued for the emissions unit(s) listed in the Authorization section of the enclosed draft permit. This draft action is not an authorization to begin construction or modification of your emissions unit(s). The purpose of this draft is to solicit public comments on the permit. A public notice will appear in the Ohio Environmental Protection Agency (Ohio EPA) [Weekly Review and Public Notices](#) website. A copy of the public notice and the draft permit are enclosed. This permit can be accessed electronically on the Ohio EPA document search webpage: [eDocument Search](#). Comments will be accepted as a marked-up copy of the draft permit or in narrative format. Any comments must be sent to the following:

Andrea Moore
Permitting Section
Ohio EPA, DAPC
50 West Town Street, Suite 700
P.O. Box 1049
Columbus, Ohio 43216-1049

and

Cleveland Division of Air Quality
2nd Floor
75 Erieview Plaza
Cleveland, OH 44114

Comments and/or a request for a public hearing will be accepted within 30 days of the date the notice is published on the Ohio EPA [Weekly Review and Public Notices](#) website. You will be notified in writing if a public hearing is scheduled. A decision on issuing a final permit-to-install will be made after consideration of comments received and oral testimony if a public hearing is conducted. Any permit fee that will be due upon issuance of a final Permit-to-Install is indicated in the Authorization section. Please do not submit any payment now. If you have any questions, please contact Cleveland Division of Air Quality at (216)664-2297.

Sincerely,

Robert Hodanbosi
Chief, Division of Air Pollution Control

cc: U.S. EPA Region 5 - Via E-Mail Notification
CDAQ; Pennsylvania; Canada

PUBLIC NOTICE

The following matters are the subject of this public notice by the Ohio Environmental Protection Agency. The complete public notice, including any additional instructions for submitting comments, requesting information, a public hearing, or filing an appeal may be obtained at: [Weekly Review and Public Notices | Ohio Environmental Protection Agency](#) or Hearing Clerk, Ohio EPA, 50 W. Town St., Columbus, Ohio 43215. Ph: 614-644-3037 email: HClerk@epa.ohio.gov

Draft Air Pollution Permit-to-Install Administrative Modification

Howmet Aerospace Inc.
1600 Harvard Avenue

Cuyahoga Heights, OH 44105-3092

ID#: P0140885

Date of Action: 08/06/2026

Permit Desc: Facility-initiated administrative modification to incorporate RACT standards. Pursuant to Part D of Title I of the Clean Air Act (CAA), Ohio EPA is required to establish a State Implementation Plan (SIP) for the attainment and maintenance of the NAAQS. The above-mentioned permit is a part of Ohio's SIP for attainment and maintenance of the 2015 ozone NAAQS and will be submitted to United States Environmental Protection Agency (U.S. EPA) as a modification of the SIP.

Howmet Aerospace is requesting a PTI administrative modification to incorporate an emission limit of 0.036 lb NOx/mmBtu for B008 and B009 for NOx RACT compliance through the use of LNB/ULNB with integrated FGR.

The permit and complete instructions for requesting information or submitting comments may be obtained at: <https://ohioepa.commentinput.com> - Search by entering the permit # P0140885 in the "Search Projects" search box.

The public comment period will run until 09/07/2026 at 11:59 PM.

Permit Strategy Write-Up

1. Check all that apply:

☐ Synthetic Minor Determination **N/A**

☐ Netting Determination **N/A**

2. Source Description:

Emissions units B008 and B009 are natural gas-fired boilers that are each rated at 98.8 mmBtu/hr.

As required by the reclassification to serious nonattainment for ozone under the 2015 ozone National Ambient Air Quality Standards (NAAQS) promulgated by U.S. EPA, this facility has submitted a NO_x Reasonably Available Control Technology (RACT) study on 4/30/2026 (subsequently revised on 5/26/2026, 7/8/2026, 7/16/2026, and 7/24/2026) to address the feasibility of controlling NO_x emissions from their two mid-size boilers (B008 and B009). This facility has no prior existing source-specific NO_x RACT under OAC rule 3745-110-03.

This permit modification includes the implementation of the proposed NO_x RACT in the 7/24/2026 revision of the RACT study. Section B.2 – B.5 of this permit identifies the NO_x RACT requirements established under OAC rule 3745-110-03(J), and the applicable rules table in Section C.1. implements this under OAC rule 3745-31-05(D) federally enforceable restriction for the affected units.

Pursuant to Part D of Title I of the Clean Air Act (CAA), Ohio EPA is required to establish a State Implementation Plan (SIP) for the attainment and maintenance of the NAAQS. This permit is part of Ohio's SIP for attainment and maintenance of the 2015 ozone NAAQS and will be submitted to United States Environmental Protection Agency (U.S. EPA) as a modification of the SIP.

3. Facility Emissions and Attainment Status:

Howmet Aerospace is a Title V facility located in Cuyahoga County.

Cuyahoga County was designated as "serious" nonattainment for the 2015 ozone NAAQS but is now a maintenance county. The county is currently designated attainment for all NAAQS (criteria) pollutants which include ozone, PM_{2.5}, PM₁₀, CO, NO₂, lead and SO₂.

4. Source Emissions:

Emissions units B008 and B009 have NO_x emissions that are subject to the NO_x RACT requirements under OAC rule 3745-110-03. Howmet Aerospace submitted a NO_x RACT study that resulted in the following NO_x RACT determination:

- a) Replacement of the existing burner systems with the installation of Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR), associated combustion controls, continued firing of natural gas, implementation of Good Combustion Practices, annual combustion tune-ups, and optimization of combustion system performance.
- b) Compliance with the NO_x RACT emission limit of 0.036 lb/mmBtu of actual heat input established under OAC rule 3745-110-03(J).



The permit includes a tentative schedule for the implementation of the above NO_x RACT control measures. The company will be required to perform stack testing after implementation of the NO_x RACT control measures in order to verify compliance with the NO_x emission limit.

With the implementation of the NO_x RACT control measures, the allowable hourly NO_x emission rate will be reduced from 14.82 pounds per hour down to 3.56 pounds per hour.

5. Conclusion:

This PTI administrative modification establishes a NO_x RACT emission limit for B008 and B009 as proposed by Howmet Aerospace Inc. in their NO_x RACT study as part of the requirements for the 2015 ozone NAAQs nonattainment and maintenance areas under the reclassification to serious nonattainment for the Cleveland area. The NO_x RACT control measures established in this permit are to be implemented within the timeline specified by the permit terms.

6. Please provide additional notes or comments as necessary:

None

7. Total Permit Allowable Emissions Summary (for informational purposes only):

<u>Pollutant</u>	<u>Tons Per Year</u>
NO _x	15.59
CO	36.4
PE	8.65
PM ₁₀	0.82



**Environmental
Protection
Agency**

DRAFT

Division of Air Pollution Control

Permit-to-Install

for

Howmet Aerospace Inc.

Facility ID:	1318170314
Permit Number:	P0140885
Permit Type:	Administrative Modification
Issued:	08/06/2026
Effective:	To be entered upon final issuance

Division of Air Pollution Control

Permit-to-Install

for

Howmet Aerospace Inc.

Table of Contents

Authorization.....	7
List of Commonly Used Abbreviations	9
A. Standard Terms and Conditions	10
B. Facility Wide Terms and Conditions.....	18
C. Emissions Unit Terms and Conditions	22
1. Emissions Unit Group - 98.8 mmBtu/hr nat gas boilers: B008, B009.....	23

Authorization

Facility ID: 1318170314
Facility Description: Aluminum forging operation
Application Number(s): M0008803
Permit Number: P0140885
Permit Type: Permit-To-Install
Permit Fee: \$600.00 *DO NOT send payment at this time, subject to change before final issuance*
Issue Date: 08/06/2026
Effective Date: To be entered upon final issuance

This document constitutes issuance of a Permit-to-Install for the emissions unit(s) identified on the following page to:

Howmet Aerospace Inc.
1600 Harvard Avenue
Cuyahoga Heights, OH 44105-3092

Ohio Environmental Protection Agency (EPA) District Office or local air agency responsible for processing and administering your permit:

Cleveland Division of Air Quality
2nd Floor
75 Erieview Plaza
Cleveland, OH 44114
(216)664-2297

The above-named entity is hereby granted this Permit-to-Install for the air contaminant source(s) (emissions unit(s)) listed in this section pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the described emissions unit(s) will operate in compliance with applicable State and Federal laws and regulations and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

John Logue

Director

Authorization (continued)

Permit Number: P0140885

Permit Description: Facility-initiated administrative modification to incorporate RACT standards. Pursuant to Part D of Title I of the Clean Air Act (CAA), Ohio EPA is required to establish a State Implementation Plan (SIP) for the attainment and maintenance of the NAAQS. The above-mentioned permit is a part of Ohio's SIP for attainment and maintenance of the 2015 ozone NAAQS and will be submitted to United States Environmental Protection Agency (U.S. EPA) as a modification of the SIP.

Howmet Aerospace is requesting a PTI administrative modification to incorporate an emission limit of 0.036 lb NOx/mmBtu for B008 and B009 for NOx RACT compliance through the use of LNB/ULNB with integrated FGR.

Permits for the following Emissions Unit(s) or groups of Emissions Units are in this document as indicated below:

Group Name: 98.8 mmBtu/hr nat gas boilers

Emissions Unit ID:	B008
Company Equipment ID:	Gas Boiler #8
Superseded Permit Number:	P0111267
General Permit Category and Type:	Not Applicable P0111267
Emissions Unit ID:	B009
Company Equipment ID:	Gas Boiler #9
Superseded Permit Number:	P0111267
General Permit Category and Type:	Not Applicable P0111267

List of Commonly Used Abbreviations

AP-42 = U.S. EPA's Compilation of Air Pollution Emissions Factors	HVLP = high volume, low pressure	PER = Permit Evaluation Report
ASTM = American Society for Testing and Materials	LAER = lowest achievable emission rate	PM = particulate matter
BACT = Best Available Control Technology	lb(s)/hr = pound(s) per hour	PM ₁₀ = particulate matter with an aerodynamic diameter less than or equal to 10 microns
BAT = Best Available Technology	LDAR = leak detection and repair	PM _{2.5} = particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
CAA = Clean Air Act	LPG = liquefied petroleum gas/propane	ppb = parts per billion
CAM = compliance assurance monitoring	MACT = maximum achievable control technology	ppm = parts per million
CEMS = continuous emissions monitoring system	MAGLC = maximum acceptable ground level concentration	PSD = Prevention of Significant Deterioration
CFC = chlorofluorocarbon	mg/m ³ = milligrams per cubic meter	psi = pounds per square inch
CFR = Code of Federal Regulations	MM = million	psia = pounds per square inch absolute
CH ₄ = methane	MMBtu = million British Thermal Units	PTE = potential-to-emit
CI = compression ignition	MSDS = material safety data sheet	PTI = Permit-to-Install
CO = carbon monoxide	MSW = municipal solid waste	PTIO = Permit-to-Install and Operate
CO ₂ = carbon dioxide	NAAQS = National Ambient Air Quality Standard	PTO = Permit-to-Operate
COM = continuous opacity monitor	NESHAP = National Emission Standard for Hazardous Air Pollutants	PWR = process weight rate
DAPC = Division of Air Pollution Control	NG = natural gas	RACM = reasonably available control measures
DO/LAA = District Office/Local Air Agency	ng/m ³ = nanograms per cubic meter	RACT = reasonably available control technology
dscf = dry standard cubic foot	NH ₃ = ammonia	RATA = relative accuracy test audit
EAC = emissions activity category	NMHC = non-methane hydrocarbons	RTO = regenerative thermal oxidizer
eDocs = electronic documents database	NMOC = non-methane organic compound	SB265 = Senate Bill 265
ERAC = Environmental Review Appeals Commission	NO = nitrogen oxide	scfm = standard cubic feet per minute
ESP = electrostatic precipitator	NO ₂ = nitrogen dioxide	SI = spark ignition
EU = emissions unit	NO _x = nitrogen oxides	SIP = State Implementation Plan
FEPTIO = Federally Enforceable Permit-to-Install and Operate	NSPS = New Source Performance Standard	SO ₂ = sulfur dioxide
FER = Fee Emissions Report	NSR = New Source Review	SSMP = startup, shutdown, and malfunction plan
FR = Federal Register	NTV = Non-Title V	TDS = total dissolved solids
GACT = generally achievable control technology	O&M = operation and maintenance	TLV = threshold limit value
GHG = greenhouse gases	OAC = Ohio Administrative Code	TO = thermal oxidizer
gr/dscf = grains per dry standard cubic foot	OC = organic compound	TPH = ton(s) per hour
H ₂ S = hydrogen sulfide	Ohio EPA = Ohio Environmental Protection Agency	TPY = ton(s) per year
H ₂ SO ₄ = sulfuric acid	ORC = Ohio Revised Code	TSP = total suspended particulates
HAP = hazardous air pollutant	Pb = lead	VE = visible particulate emissions
HCl = hydrogen chloride	PBR = Permit-By-Rule	VMT = vehicle miles traveled
HF = hydrogen fluoride	PCB = polychlorinated biphenyl	VOC = volatile organic compound
Hg = mercury	PE = particulate emissions	WPP = work practice plan
hp = horsepower	PEMS = predictive emissions monitoring system	µg/m ³ = micrograms per cubic meter



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Draft Permit-to-Install

Howmet Aerospace Inc.

Permit Number: P0140885

Facility ID: 1318170314

Effective Date: To be entered upon final issuance

A. Standard Terms and Conditions



1. Federally Enforceable Standard Terms and Conditions

- a) All Standard Terms and Conditions are federally enforceable, with the exception of those listed below which are enforceable under state law only:
 - (1) Standard Term and Condition A.2.a), Severability Clause
 - (2) Standard Term and Condition A.3.c) through A. 3.e), General Requirements
 - (3) Standard Term and Condition A.6.c), Compliance Requirements
 - (4) Standard Term and Condition A.8., Air Pollution Nuisance
 - (5) Standard Term and Condition A.9., Reporting Requirements
 - (6) Standard Term and Condition A.10., Applicability
 - (7) Standard Term and Condition A.11.b) through A.11.e), Construction of New Source(s) and Authorization to Install
 - (8) Standard Term and Condition A.14., Public Disclosure
 - (9) Standard Term and Condition A.15., Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations
 - (10) Standard Term and Condition A.16., Fees
 - (11) Standard Term and Condition A.17., Permit Transfers

2. Severability Clause

- a) A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.
- b) All terms and conditions designated in parts B. and C. of this permit are federally enforceable as a practical matter, if they are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the state and by citizens (to the extent allowed by section 304 of the Act) under the Act. Terms and conditions in parts B and C of this permit shall not be federally enforceable and shall be enforceable under state law only, only if specifically identified in this permit as such.

3. General Requirements

- a) Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act and is grounds for enforcement action or for permit revocation, revocation and re-issuance, or modification.
- b) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.



- c) This permit may be modified, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.
- d) This permit does not convey any property rights of any sort, or any exclusive privilege.
- e) The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

4. Monitoring and Related Record Keeping and Reporting Requirements

- a) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:
 - (1) The date, place (as defined in the permit), and time of sampling or measurements.
 - (2) The date(s) analyses were performed.
 - (3) The company or entity that performed the analyses.
 - (4) The analytical techniques or methods used.
 - (5) The results of such analyses.
 - (6) The operating conditions existing at the time of sampling or measurement.
- b) Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.
- c) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:
 - (1) Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the Cleveland Division of Air Quality.
 - (2) Quarterly written reports of (i) any deviations from federally enforceable emission limitations, operational restrictions, and control device operating parameter limitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the Cleveland Division of Air Quality. The written reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each



year and shall cover the previous calendar quarters. See A.15. below if no deviations occurred during the quarter.

- (3) Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, and reporting requirements contained in this permit shall be submitted to the Cleveland Division of Air Quality every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semiannual report, which states that no deviations occurred during that period.
 - (4) This permit is for an emissions unit located at a Title V facility. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
- d) The permittee shall report actual emissions pursuant to OAC Chapter 3745-78 for the purpose of collecting Air Pollution Control Fees.

5. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the Cleveland Division of Air Quality in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.

Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

6. Compliance Requirements

- a) All applications, notifications or reports required by terms and conditions in this permit to be submitted or "reported in writing" are to be submitted to Ohio EPA through the Ohio EPA's eBusiness Center: Air Services web service ("Air Services"). Ohio EPA will accept hard copy submittals on an as-needed basis if the permittee cannot submit the required documents through the Ohio EPA eBusiness Center. In the event of an alternative hard copy submission in lieu of the eBusiness Center, the post-marked date or the date the document is delivered in person will be recognized as the date submitted. Electronic submission of applications, notifications or reports required to be submitted to Ohio EPA fulfills the requirement to submit the required information to the Director, the appropriate Ohio EPA District Office or contracted local air agency, and/or any other individual or organization specifically identified as an additional recipient identified in this permit unless otherwise specified. Consistent with OAC rule 3745-15-03, the electronic signature date shall constitute the date that the required application, notification or report is considered to be "submitted". Any document requiring signature may be represented by entry of the personal identification number (PIN) by responsible official as part of the electronic submission process or by the scanned attestation document signed by the Authorized Representative that is attached to the electronically submitted written report.



Any document (including reports) required to be submitted and required by a federally applicable requirement in this permit shall include a certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete

- b) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:
 - (1) At reasonable times, enter upon the permittee's premises where a source is located, or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.
 - (2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.
 - (3) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.
 - (4) As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.
- c) The permittee shall submit progress reports to the Cleveland Division of Air Quality concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:
 - (1) Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.
 - (2) An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

7. Best Available Technology

As specified in OAC Rule 3745-31-05, new sources that must employ Best Available Technology (BAT) shall comply with the Applicable Emission Limitations/Control Measures identified as BAT for each subject emissions unit.

8. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

9. Reporting Requirements

The permittee shall submit required reports in the following manner:

- a) Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the Cleveland Division of Air Quality.
- b) Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected



by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the Cleveland Division of Air Quality. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

10. Applicability

This permit-to-install is applicable only to the emissions unit(s) identified in the permit-to-install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s) not exempt from the requirement to obtain a permit-to-install.

11. Construction of New Sources(s) and Authorization to Install

- a) This permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. This permit does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the application and terms and conditions of this permit. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of this permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Issuance of this permit is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities cannot meet the requirements of this permit or cannot meet applicable standards.
- b) If applicable, authorization to install any new emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation. This deadline may be extended once by twelve months if application is made to the Director within a reasonable time before the termination date and the permittee shows good cause for any such extension.
- c) The permittee may notify Ohio EPA of any emissions unit that is permanently shut down (i.e., the emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31) by submitting a certification from the authorized official that identifies the date on which the emissions unit was permanently shut down. Authorization to operate the affected emissions unit shall cease upon the date certified by the authorized official that the emissions unit was permanently shut down. At a minimum, notification of permanent shut down shall be made or confirmed by marking the affected emissions unit(s) as "permanently shut down" in "Air Services" along with the date the emissions unit(s) was permanently removed and/or disabled. Submitting the facility profile update electronically will constitute notifying the Director of the permanent shutdown of the affected emissions unit(s).
- d) The provisions of this permit shall cease to be enforceable for each affected emissions unit after the date on which an emissions unit is permanently shut down (i.e., emissions unit has been physically



removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31). All records relating to any permanently shut down emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law. All reports required by this permit must be submitted for any period an affected emissions unit operated prior to permanent shut down. At a minimum, the permit requirements must be evaluated as part of the reporting requirements identified in this permit covering the last period the emissions unit operated.

Unless otherwise exempted, no emissions unit certified by the responsible official as being permanently shut down may resume operation without first applying for and obtaining a permit pursuant to OAC Chapter 3745-31 and OAC Chapter 3745-77 if the restarted operation is subject to one or more applicable requirements.

- e) The permittee shall comply with any residual requirements related to this permit, such as the requirement to submit a deviation report, air fee emission report, or any other reporting required by this permit for the period the operating provisions of this permit were enforceable, or as required by regulation or law. All reports shall be submitted in a form and manner prescribed by the Director. All records relating to this permit must be maintained in accordance with law.

12. Permit-To-Operate Application

The permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77. The permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve months after commencing operation of the emissions units covered by this permit. However, if operation of the proposed new or modified source(s) as authorized by this permit would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d) must be obtained before operating the source in a manner that would violate the existing Title V permit requirements.

13. Construction Compliance Certification

The applicant shall identify the following dates in the "Air Services" facility profile for each new emissions unit identified in this permit.

- a) Completion of initial installation date shall be entered upon completion of construction and prior to start-up.
- b) Commence operation after installation or latest modification date shall be entered within 90 days after commencing operation of the applicable emissions unit.

14. Public Disclosure

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

15. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

16. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable permit-to-install fees within 30 days after the issuance of any permit-to-install. The permittee shall pay all applicable permit-to-operate fees within thirty days of the issuance of the invoice.

17. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The new owner must update and submit the ownership information via the "Owner/Contact Change" functionality in "Air Services" once the transfer is legally completed. The change must be submitted through "Air Services" within thirty days of the ownership transfer date.

18. Risk Management Plans

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

19. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.



B. Facility Wide Terms and Conditions

1. All the following facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

- a) None.

2. **OAC rule 3745-110-03(J) NO_x RACT for Sources in Ozone Nonattainment and Maintenance Areas**

As required by the reclassification to serious nonattainment for ozone under the 2015 ozone National Ambient Air Quality Standards promulgated by U.S. EPA, and pursuant to OAC rule 3745-110-03(J) and the NO_x Reasonable Available Control Technology (RACT) Study submitted by Howmet Aerospace, Inc. on 4/30/2026, 5/26/2026, 7/8/2026, and 7/16/2026:

“Howmet Aerospace, Inc.” (facility ID 1318170314), or any subsequent owner or operator of the “Howmet Aerospace, Inc.” facility located at 1600 Harvard Avenue, Cleveland, Ohio, shall comply with the following for emissions units B008 and B009:

- a) Replacement of the existing burner systems with the installation of Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR), associated combustion controls, continued firing of natural gas, implementation of Good Combustion Practices, annual combustion tune-ups, and optimization of combustion system performance.

- b) Compliance with the NO_x RACT emission limit of 0.036 lb/mmBtu of actual heat input established under OAC rule 3745-110-03(J). (This emission limit shall apply after implementation of the NO_x RACT control measures per the schedule in B.5. below.)

Note that adjustments to this emission limit might be needed based on the results of the stack test that will be performed for each boiler after implementation of the NO_x RACT control measures.

- c) Install, maintain, and operate the equipment in accordance with the manufacturer's recommendations, instructions, and operating manual(s) with any modifications deemed necessary by the permittee with good combustion practices and proper boiler operation for the control of NO_x emissions from these EUs.

3. **Monitoring and/or Recordkeeping requirements**

- a) In order to ensure emissions units B008 and B009 continue to operate as designed after implementation of the NO_x RACT control measures, the permittee shall operate these boilers and associated equipment in accordance with the manufacturer's recommendations, instructions, and operating manual(s) with any modifications deemed necessary by the permittee. The manufacturer's recommendations, instructions, and operating manual(s), with any modification documents, shall be maintained for the life of the boilers.

The permittee shall perform the recommended maintenance at the recommended intervals. The permittee shall keep records of the maintenance performed on these boilers and shall retain them for a period of five years from the date the record was created.

- b) The permittee shall annually perform a tune-up for emissions units B008 and B009 and maintain, in a permanently bound log book, or other equivalent electronic method that ensures data integrity, the following information:

- (1) The date of the last tune-up.



- (2) The name, title and affiliation of the person who performed the tune-up and made any adjustments.

"Tune-up" means adjustments made to a burner or boiler in accordance with procedures supplied by the manufacturer (or approved specialist) to optimize the combustion efficiency.

4. Testing Requirements

a) Emission Limitation:

NO_x emissions shall not exceed 0.036 lb/mmBtu of actual heat input, for each emissions unit (B008 and B009).

(This emission limit shall apply after implementation of the NO_x RACT controls per the schedule in B.5. below).

Note that adjustments to this emission limit might be needed based on the results of the stack test that will be performed for each boiler after implementation of the NO_x RACT control measures.

Applicable Compliance Method:

The natural gas-fired boilers (B008 and B009) shall be equipped with Low NO_x Burners (LNB/Ultra-Low NO_x Burners and integrated Flue Gas Recirculation (FGR) equipment that is designed to meet a NO_x emission rate of 0.036 lb/mmBtu of actual heat input which satisfies the NO_x RACT requirement under OAC rule 3745-110-03(J).

Compliance shall be determined through emission testing conducted in accordance with USEPA Methods 1 through 4 and 7 of 40 CFR, Part 60, Appendix A. See B.4.b).

b) The permittee shall conduct, or have conducted, emissions testing for emissions units B008 and B009 per the following requirements:

- (1) The emission testing shall be conducted within three months after implementation of the NO_x RACT controls per the schedule in B.5. below.

- (2) The emission testing shall be conducted to demonstrate compliance with the allowable NO_x RACT emission limit of 0.036 lb/mmBtu of actual heat input for each boiler.

- (3) The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate:

NO_x: USEPA methods 1 – 4 and 7 of 40 CFR Part 60, Appendix A

Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

- (4) During the emissions testing, the EU shall be operated under operational conditions approved in advance by the Cleveland Division of Air Quality (Cleveland DAQ). Operational conditions that may need to be approved include, but are not limited to, the production rate, the type of material processed, material make-up (solvent content, etc.) or control equipment operational limitations (burner temperature, precipitator voltage, etc.). In general, testing shall be done under worst case conditions expected during the life of the permit. As part of the information provided in the Intent to Test (ITT) notification form described below, the permittee shall provide a description of the EU operational conditions they will meet during the emissions testing and describe why they believe worst case operating conditions will be met. Prior to



conducting the test(s), the permittee shall confirm with the Cleveland DAQ that the proposed operating conditions constitute worst case. Failure to test under the approved conditions may result in Ohio EPA not accepting the test results as a demonstration of compliance.

- (5) Not later than 30 days prior to the proposed test date(s), the permittee shall submit an ITT notification to the Cleveland DAQ. The ITT notification shall describe in detail the proposed test methods and procedures, the EU operating parameters, the time(s) and date(s) of the test(s) and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Cleveland DAQ's refusal to accept the results of the emission test(s).
- (6) Personnel from the Cleveland DAQ shall be permitted to witness the test(s), examine the testing equipment and acquire data and information necessary to ensure that the operation of the EU and the testing procedures provide a valid characterization of the emissions from the EU and/or the performance of the control equipment.
- (7) A comprehensive written report on the results of the emissions test(s) shall be signed by the person(s) responsible for the tests and submitted to the Cleveland DAQ within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Cleveland DAQ.

5. Miscellaneous Requirements

a) Tentative NOx RACT implementation schedule:

Milestone	Completion Date *	Cumulative Time (days) from Ohio EPA Approval
Final Ohio EPA NOx RACT Approval	8/1/2026	0
Field Engineering	8/1/2026 – 1/1/2027	153
PTI Application/Issuance	1/28/2027	180
Equipment Fabrication and Delivery	2/1/2027 – 8/1/2027	365
Outage #1	9/1/2027 – 11/30/2027	486
Start-up	11/30-2027 – 12/30/2027	516
Outage #2	4/1/2028 – 6/30/2028	699
Start-up	7/1/2028 – 7/31/2028	730

* Dates are subject to change depending on the actual date of action.



C. Emissions Unit Terms and Conditions



1. Emissions Unit Group - 98.8 mmBtu/hr nat gas boilers: B008, B009

EU ID	Operations, Property and/or Equipment Description
B008	Nebraska Boiler Company model NS-F-73SH: 98.8 mmBtu/hr natural gas-fired boiler, equipped with Low-NOx Burners (LNB/ULNB) with integrated Flue Gas Recirculation [per schedule in B.5.]
B009	Nebraska Boiler Company model NS-F-73SH: 98.8 mmBtu/hr natural gas-fired boiler, equipped with Low-NOx Burners (LNB/ULNB) with integrated Flue Gas Recirculation [per schedule in B.5.]

- a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

- b) Applicable Emissions Limitations and/or Control Requirements

- (1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) See g)(2) below.	Lower nitrogen oxide (NO _x) burners and pollutant specific emission limits. See b)(2)a. through b)(2)c. below. This rule also includes compliance with the requirements of OAC rules 3745-17-07(A)(1), 3745-17-10(B)(1), and 3745-31-05(D).
b.	OAC rule 3745-31-05(D) [Federally Enforceable Requirements to comply with OAC rule 3745-110-03(J)]	See Facility-Wide Section B.2 – B.5 above.
c.	OAC rule 3745-110-03(J)	The NO _x RACT determination in accordance with this rule is equivalent to the lb NO _x /mmBtu emission limit established pursuant to OAC rule 3745-31-05(D).
d.	OAC rule 3745-17-07(A)(1)	Visible particulate emissions from the exhaust stack shall not exceed 20% opacity, as a 6-minute average, except as provided by rule, for each emissions unit.



Effective Date: To be entered upon final issuance

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
e.	OAC rule 3745-17-10(B)(1)	Particulate emissions (PE) shall not exceed 0.020 lb per mmBtu of actual heat input, for each emissions unit.
f.	OAC rule 3745-18-06(D)	There are no sulfur dioxide (SO ₂) emission limitations when burning only natural gas.
g.	OAC rule 3745-110-03(K)(17) (as effective prior to 4/1/2025)	Nitrogen Oxide (NO _x) emissions shall not exceed 25 tons per year (TPY) as a rolling, 12-month summation. (This emission limit shall expire after implementation of the NO _x RACT controls per the schedule in section B.5. above.) See d)(1), e)(4), and f)(1)g. below.
h.	40 CFR, Part 60, Subpart Dc	See b)(2)d. below.
i.	40 CFR Part 63, Subpart JJJJJJ	See b)(2)e. below.

(2) Additional Terms and Conditions

- a. Allowable mass emissions shall not exceed the following when burning natural gas, for each emissions unit:
- Nitrogen Oxide (NO_x): 14.82 lbs/hr (this limit shall expire after implementation of the NO_x RACT controls per the schedule in section B.5. above)
- Nitrogen Oxide (NO_x): 3.56 lbs/hr (this limit shall apply after implementation of the NO_x RACT controls per the schedule in section B.5. above)
- Carbon monoxide (CO): 8.30 lbs/hr
- PM₁₀ emissions: 0.188 lb/hr
- b. The annual emissions from each boiler shall not exceed the following (these limits shall expire after implementation of the NO_x RACT controls per the schedule in section B.5. above):
- i. 25 tons/year NO_x
 - ii. 13.9 tons/year CO
 - iii. 3.33 tons/year PE
 - iv. 0.31 tons/year PM₁₀



- c. The annual emissions from each boiler shall not exceed the following based on maximum potential to emit (these limits shall apply after implementation of the NOx RACT controls per the schedule in section B.5. above):
 - i. 15.59 tons/year NOx
 - ii. 36.4 tons/year CO
 - iii. 8.65 tons/year PE
 - iv. 0.82 ton/year PM₁₀
- d. So long as only natural gas fuel is burned, this emissions unit is not subject to the emission limits listed in 40 CFR Part 60, Subpart Dc.
- e. So long as only natural gas fuel is burned, this emissions unit is not subject to the emission limits listed in 40 CFR Part 63, Subpart JJJJJJ.
- f. See Facility-Wide Section B.2 – B.5 above.

c) Operational Restrictions

- (1) The permittee shall burn only natural gas in this emissions unit.

d) Monitoring and/or Recordkeeping Requirements

- (1) The permittee shall maintain monthly records of the following information:
 - a. the amount, in million cubic feet (mmcf) per month, of natural gas burned; and
 - b. the NOx emissions, in tons/month, and the rolling, 12-month summation of NOx emissions calculated in accordance with f)(1)g. below.

(This term shall expire after implementation of the NOx RACT controls per the schedule in B.5. above)

- (2) For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

e) Reporting Requirements

- (1) The reports contained in this permit shall be submitted in accordance with the reporting requirements specified in Section A, Standard Terms and Conditions.
- (2) Unless other arrangements have been approved by the director, all notifications and reports shall be submitted through Ohio EPA's eBusiness Center: Air Services online web portal.
- (3) The permittee shall submit deviation (excursion) reports to the Cleveland Division of Air Quality (Cleveland DAQ) that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.
- (4) The permittee shall submit deviation (excursion) reports to the Cleveland DAQ that identify any exceedance of the rolling, 12-month NOx limitation of 25 tons. The deviation (excursion) reports shall be submitted to the Cleveland DAQ within 30 days after the exceedance occurs.

(This term shall expire after implementation of the NOx RACT controls per the schedule in B.5. above.)



f) Testing Requirements

- (1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

Visible particulate emissions from any exhaust stack shall not exceed 20% opacity (6-minute average), except as provided by OAC rule 3745-17-07(A), for each emissions unit.

Applicable Compliance Method:

Compliance shall be determined through visible emission observations performed in accordance with USEPA Test Method 9 of 40 CFR, Part 60, Appendix A and the procedures specified in OAC rule 3745-17-03(B)(1). This compliance method shall be used whenever a compliance determination is warranted.

b. Emission Limitation:

Particulate emissions (PE) shall not exceed 0.020 lb per mmBtu of actual heat input, for each emissions unit.

Applicable Compliance Method:

For natural gas, compliance may be determined by dividing the emission factor of 1.9 lbs PE/mmcf for natural gas by the natural gas gross heating value of 1,020 mmBtu/mmcf. This emission factor is specified in the USEPA's Compilation of Air Pollution Emission Factors, AP-42, Fifth Edition, Section 1.4, Table 1.4-2 (7/98).

Actual PE rate = (1.9 lbs PE/mmcf) x (mmcf/1,020 mmBtu) = 0.0019 lb PE/mmBtu

If required, compliance shall be demonstrated based on emission testing in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

c. Emission Limitation:

Particulate emissions (PM₁₀) shall not exceed 0.188 lb/hr, for each emissions unit.

Applicable Compliance Method:

For natural gas, compliance may be determined by multiplying the lb PE/mmBtu emission rate calculated in f)(1)b. by the maximum hourly heat input of the emissions unit (98.8 mmBtu/hr).

If required, compliance shall be demonstrated based on emission testing in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

d. Emission Limitation:

Carbon monoxide (CO) emissions shall not exceed 8.30 lbs/hr when burning natural gas, for each emissions unit.

Applicable Compliance Method:

Compliance may be determined by multiplying the appropriate emission factor for natural gas from USEPA's Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Section 1.4, Table 1.4-1 (7/98) and the maximum boiler heat input in mmBtu/hr,



and then dividing the resultant product by the natural gas gross heating value of 1,020 mmBtu/mmcf.

Actual hourly CO emission rate = (84 lbs CO/mmcf) x (98.8 mmBtu/hr) x (mmcf/1,020 mmBtu) = 8.30 lbs CO/hr

If required, the permittee shall demonstrate compliance with the hourly emission limitations through emission testing conducted in accordance with Methods 1 through 4, and 10 of 40 CFR Part 60, Appendix A.

e. Emission Limitation:

The annual emissions from each boiler shall not exceed the following:

13.9 tons per year CO;

3.33 tons per year PE; and

0.31 ton per year PM₁₀.

(These emission limits shall expire after implementation of the NOx RACT controls per the schedule in section B.5. above.)

Applicable Compliance Method:

The annual emission rate in tons per year for each boiler when burning natural gas may be determined by multiplying the appropriate emission factor in lbs/mmcf by the natural gas usage in mmcf/year, and then dividing the resultant product by a factor of 2,000 lbs/ton.

The emission factors for burning natural gas are specified in USEPA's Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Tables 1.4-1 and 1.4-2 (7/98).

In addition, the permittee may utilize emission factors for natural gas that are based upon emission testing performed for this emissions unit or an identical unit.

Actual annual emission rate (tons/yr) = (lbs pollutant/mmcf) x (mmcf natural gas/yr) x (ton/2,000 lbs)

f. Emission Limitation:

Nitrogen oxide (NOx) emissions shall not exceed 14.82 lbs/hr.

(This emission limit shall expire after implementation of the NOx RACT controls per the schedule in section B.5. above.)

Applicable Compliance Method:

Compliance with the lb/hr emission limitation was demonstrated through performance testing conducted in August 2010. The average emission factor established for NOx emissions was 0.15 lb/mmBtu. This emissions factor is multiplied by the maximum heat input of the boiler (98.8 mmBtu/hr) to arrive at the lbs/hr emission rate.

If required, the permittee shall demonstrate compliance with the hourly emission limitations through emission testing conducted in accordance with Methods 1 through 4, and 7 of 40 CFR Part 60, Appendix A.



g. Emission Limitation:

NOx emissions shall not exceed 25 TPY per rolling, 12-month summation.

(This emission limit shall expire after implementation of the NOx RACT controls per the schedule in section B.5. above.)

Applicable Compliance Method:

Compliance with the annual NOx emission limitation shall be determined through use of the following equation using the emission factor established during the performance test conducted in August 2010, the natural gas gross heating value, the monthly amount of natural gas burned and the conversion factor of 2,000 lbs/ton:

$$(0.15 \text{ lb NOx/mmBtu}) \times (1,020 \text{ mmBtu/mmcf}) \times (\text{mmcf of natural gas burned/month}) \times (\text{ton}/2,000 \text{ lbs}) = \text{tons NOx/month}$$

The monthly emissions shall then be added together to determine the rolling, 12-month summation.

h. Emission Limitation:

NOx emissions shall not exceed 3.56 lbs/hr

(This limit shall apply after implementation of the NOx RACT controls per the schedule in section B.5. above.)

Applicable Compliance Method

Compliance with the lb/hr emission limitation shall be demonstrated through performance testing conducted in accordance with Section B.4. above. The stack test will provide an average emission rate for NOx emissions in lb NOx/mmBtu. This emission rate is multiplied by the maximum heat input of the boiler (98.8 mmBtu/hr) to arrive at the lbs/hr emission rate.

The permittee shall demonstrate compliance with the hourly emission limitations through emission testing conducted in accordance with Methods 1 through 4, and 7 of 40 CFR Part 60, Appendix A. See Section B.4. above.

i. Emission Limitation:

The annual emissions from each boiler shall not exceed the following based on maximum potential to emit:

15.59 tons per year NOx;

36.4 tons per year CO;

8.65 tons/year PE; and

0.82 ton per year PM₁₀.

(These emission limits shall apply after implementation of the NOx RACT controls per the schedule in section B.5. above.)



Applicable Compliance Method:

The annual emission limit in tons per year for each boiler when burning natural gas was determined by multiplying the pound/hour emission rate by 8760 hours/year, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is maintained with the hourly emission limits then compliance shall also be determined for the annual emission limit.

$$\text{Annual emission limit (tons/yr)} = (\text{lbs pollutant/hour}) \times (8760 \text{ hrs/yr}) \times (\text{ton}/2,000 \text{ lbs})$$

g) Miscellaneous Requirements

- (1) Emissions units B008 and B009 were each installed in 1997.
- (2) The following PTIs were previously issued for emissions units B008 and B009:
PTI #13-3174 issued June 20, 1997; and
PTI P0111267 issued November 13, 2012.

**NO_x REASONABLY AVAILABLE
CONTROL TECHNOLOGY (RACT)
STUDY PER OHIO ADMIN. CODE
OAC 3745-110**

Howmet Aerospace, Inc. – Cleveland
Operations
Evaluation of Boilers B008 and B009 and
RACT Exemption Evaluation for Other
Natural Gas-Fired Combustion Sources
Version 5
(Revision 4.0)

Prepared For

Howmet Aerospace, Inc.
1600 Harvard Avenue
Cuyahoga Heights, Ohio 44105
Facility ID 13-18-17-0314
PTI ID P0111267
Title V Permit No. P0135538

Project No. M261629

July 24, 2026





**Reasonably Available Control Technology (RACT) Engineering Study for
NOx Controls for Boilers B008 and B009 and RACT Exemption Evaluation
for Other Natural Gas-Fired Combustion Sources**

**VERSION 5
(Revision 4.0)**

Howmet Aerospace Inc. – Cleveland Operations
1600 Harvard Avenue, Cuyahoga Heights, Ohio 44105

Facility ID 13-18-17-0314
PTI ID P0111267
Title V Permit No. P0135538

PREPARED BY MOSTARDI PLATT
888 Industrial Drive
Elmhurst, Illinois 60126

Table of Contents

1. Executive Summary	1
1.1 Control Technology Evaluation	2
1.2 Proposed RACT Determination	2
2. Facility Information	10
2.1 Name and Address	10
2.2 Owner Representative Information	10
2.3 Study Approval Officer	10
2.4 Standard Industrial Classification (SIC/NAICS) and Source Classification Code (SCC)	10
2.5 General Source Information	10
2.5.1 Ohio EPA Application Number (PTI ID):	10
2.5.2 Title V Permit Number:	10
2.5.3 Facility Identification Number (Facility ID):	10
2.5.4 Facility Longitudinal and Latitudinal Coordinates	10
2.5.5 Facility Location	11
3. Regulatory Framework and RACT Methodology	21
3.1 Ohio EPA NO _x RACT Regulatory Framework	21
3.2 Top-Down Methodology and Analysis Procedure	22
4. Process and Boiler Description	24
4.1 Unit History and Baseline Performance	25
4.2 Analysis of April 2026 Stack Test Data	25
4.3 Comparative Evaluation	25
5. Baseline NO _x Emissions and Representative Operating Basis	26
5.1 Historical Annual Emissions and Operating Profile	26
5.2 Average vs. Maximum Daily Emissions	27
5.3 Potential to Emit (PTE)	28
5.4 Historical NO _x Emissions Inventory for Remaining Natural Gas-Fired Combustion Sources	28
5.5 Emission Unit P162 Applicability Determination	31
6. Identification of Available Control Technologies	32
6.1.1 Engineering Evaluation Methodology for Remaining Natural Gas-Fired Combustion Sources	32
6.1.2 Operational and Combustion Optimization Controls	34
6.1.3 Combustion Modification Technologies	34
6.1.4 Post-Combustion Control Systems	34
6.1.5 Incompatible Source-Category and Fuel-Based Controls	35
6.2 Technical Discussion of Evaluated Technologies	38
6.3 Evaluation of Individual NO _x Control Technologies Considered	39
6.3.1 Combustion Tuning / Low Excess Air	39
6.3.2 Low-NO _x Burners (LNB/ULNB)	39
6.3.3 Flue Gas Recirculation (FGR)	39
6.3.4 Selective Catalytic Reduction (SCR)	39
6.3.5 Selective Non-Catalytic Reduction (SNCR)	40
6.3.6 Other Control Technologies Evaluated	40
6.4 Engineering Evaluation of Common-Control Feasibility for Remaining Natural Gas-Fired Combustion Sources	41
6.4.1 Group 1 – A-Plant (Buildings 200, 206, and 210)	41
6.4.2 Group 2 – S-Plant (Building 150)	42
6.4.3 Group 3 – Building 120	43
6.4.4 Group 4 – H-Plant/Remaining Small Furnace Group (Buildings 101, 111, 112, and 114)	43
6.4.5 Summary of Common-Control Feasibility Evaluation	44
7. Technical Feasibility Screening	49
7.1 Technical Feasibility Screening for Remaining Natural Gas-Fired Combustion Sources	50
8. Control Effectiveness Ranking	52
9. Cost Analysis	54
9.1 SCR Cost Analysis	56
9.2 SNCR Cost Analysis	57
9.3 Burner Controls, FGR, and LNB/ULNB Cost Analysis	57
9.4 Economic Evaluation of Representative Combustion-Source Groups	58
9.4.1 Selection of Representative Common-Control Technology for Economic Evaluation	59
9.4.2 Representative Common-Control Cost Basis	60

9.4.3 Group 1 – A-Plant Representative Common-Control Cost Evaluation	61
9.4.4 Group 2 – S-Plant Representative Common-Control Cost Evaluation	62
9.4.5 Group 3 – Building 120 Representative Common-Control Cost Evaluation	62
9.4.6 Group 4 – H-Plant Representative Common-Control Evaluation	63
9.4.7 Summary of Representative Common-Control Economic Evaluation	64
10. Cost-Effectiveness Comparison	65
11. RACT Determination	70
11.1 Source-Specific RACT Determination – Boilers B008 and B009	70
11.2 Evaluation of NO _x Control Technologies Identified in OAC 3745-110-03(J)(1)(h)	73
11.2.1 Low-NO _x Burners (LNB)	73
11.2.2 Ultra-Low-NO _x Burners (ULNB)	74
11.2.3 Close-Coupled or Separated Over-Fire Ports	75
11.2.4 Flue Gas Recirculation (FGR)	76
11.2.5 Low-NO _x Burners with External Flue Gas Recirculation (LNB + External FGR)	77
11.2.6 Burners Out of Service	78
11.2.7 Steam or Water Injection	79
11.2.8 Dry Low-NO _x Burners	80
11.2.9 Ignition Timing Retard	80
11.2.10 Separate Circuit After-Cooling	81
11.2.11 Fuel Emulsification	82
11.2.12 Selective Non-Catalytic Reduction (SNCR)	83
11.2.13 Nonselective Catalytic Reduction (NSCR)	84
11.2.14 Selective Catalytic Reduction (SCR) Using Urea, Ammonia, or Methane	85
11.2.15 Incineration (for Sources Other Than Boilers)	86
11.2.16 Scrubbing (for Sources Other Than Boilers)	86
11.2.17 Process Modification	87
11.2.18 Fuel Switching	88
11.2.19 Adjustment of Air/Fuel Ratio (Internal Combustion Engines Only)	89
11.2.20 Low Excess Air	90
11.2.21 Mid-Kiln Firing	91
11.2.22 Mid-Kiln Air Injection	92
11.2.23 Gaseous Fuels Reburn	93
11.2.24 Other RACT Alternatives	94
12. Implementation Considerations	95
12.1 Proposed RACT Implementation Schedule	95
13. Engineering Limitations and Future Considerations	97
14. References	98
15. Summary	99
Appendix A. Calculation Notes	101
Appendix B. Detailed Study-Level Cost Worksheets	102
Appendix C. Technical Feasibility Elimination Detail	106
Appendix D. Sensitivity Analysis	107

List of Tables

Table 1-1. Summary of RACT Findings for Boilers B008 and B009.....	3
Table 1-2. Summary of Other Combustion Source Emission Units (Facility-Wide)	3
Table 1-3. Common-Control Grouping Summary for Other Natural Gas-Fired Combustion Sources	5
Table 1-4. Unit Listing by Common-Control Group.....	6
Table 3-1. Top-Down RACT Selection Methodology and Evaluation Criteria	23
Table 4-1. Boiler Description and Permit-derived Engineering Baseline.....	24
Table 5-1. Historical Operational Baseline and Actual Emissions (2023 – 2025)	26
Table 5-2. Historical Annual NOx Emissions Summary (2023 – 2025)	26
Table 5-3. Historical Estimated Average and Maximum Daily NOx Emissions (2023 – 2025)	27
Table 5-4. Historical NOx Emissions Summary for Remaining Gas-Fired Combustion Sources (Average Daily NOx)	28
Table 5-5. Historical NOx Emissions Summary for Remaining Gas-Fired Combustion Sources (Tons of NOx Per Year).....	29
Table 6-1. Representative Engineering Grouping of Remaining Natural Gas-Fired Combustion Sources for Common-Control Evaluation	33
Table 6-2. Identification of Potential NOx Control Technologies for Boilers B008 and B009.....	36
Table 6-3. Summary of Evaluated NOx Control Technologies and Screening Considerations	37
Table 6-4. Representative Engineering Characteristics of Group 1 – A-Plant (Buildings 200, 206, and 210).....	42
Table 6-5. Representative Engineering Characteristics of Group 2 – S-Plant (Building 150).....	42
Table 6-6. Representative Engineering Characteristics of Group 3 – Building 120	43
Table 6-7. Representative Engineering Characteristics of Group 4 – H-Plant/Remaining Small Furnace Group (Buildings 101, 111, 112, and 114)	44
Table 6-8. Summary of Engineering Evaluation of Common-Control Feasibility	45
Table 6-9. Summary of RACT Feasibility Conclusions for Combustion Source Groupings.....	46
Table 6-10. Evaluation of OAC Rule 3745-110-03(J)(1)(h) NOx Control Measures for the Representative Engineering Groups	47
Table 7-1. Technical Feasibility Screening Matrix	49
Table 8-1. Ranking of Feasible NOx Control Technologies by Effectiveness	52
Table 8-2. Representative Ranking of Retained NOx Control Technologies	53
Table 9-1. Capital Cost and Annual O&M Assumptions (Boilers B008/B009)	54
Table 9-2. Annualized Cost Assumptions (Boilers B008/B009)	55
Table 9-3. Representative Common-Control Systems Selected for Evaluation	59
Table 9-4. Representative Conceptual Design Basis	61
Table 9-5. Group 1 – A-Plant Representative Common-Control Cost Evaluation.....	62
Table 9-6. Group 2 – S-Plant Representative Common-Control Cost Evaluation.....	62
Table 9-7. Group 3 – Building 120 Representative Common-Control Cost Evaluation.....	63
Table 9-8. Group 4 – H-Plant Representative Common-Control Cost Evaluation	64
Table 10-1. Cost Effectiveness Relative to 2025 Actual Baseline and PTE Sensitivity	67
Table 10-2. Approximate Controlled Emission Rates and Comparative Cost Effectiveness	68
Table 11-1. Comparative Evaluation of Source-Specific RACT Control Options for Boilers B008 and B009.....	72
Table 12-1. Proposed RACT Implementation and Follow-up Considerations	96
Appendix Table A-1. Calculation Bases and Notes	101
Appendix Table B-1. Stack Test Run Fuel Use and Calculated Heat Input per Boiler	102
Appendix Table B-2. Combustion Tune-up / Burner Optimization Cost Worksheet per Boiler	102
Appendix Table B-3. Oxygen Trim / Combustion Control Modernization Cost Worksheet per Boiler.....	103
Appendix Table B-4. Low Excess Air Optimization Cost Worksheet per Boiler	103
Appendix Table B-5. FGR Retrofit / Fan and Duct Modification Cost Worksheet per Boiler.....	103
Appendix Table B-6. LNB/ULNB + Induced FGR + Controls Cost Worksheet per Boiler	104
Appendix Table B-7. SNCR Cost Worksheet per Boiler.....	104
Appendix Table B-8. SCR Cost Worksheet per Boiler.....	105
Appendix Table C-1. Detailed Technical Screening Rationale for Controls Eliminated or Retained Only Conditionally	106
Appendix Table D-1. Sensitivity of NOx Control Cost Effectiveness to Baseline Operating Assumptions	108

List of Figures

Figure 1. Site Diagram of the Facility	12
Figure 2. Aerial View of the Facility, with Boundary and Building 45 Location	13
Figure 3. Emission Units Call-Outs	14
Figure 4. Building 45 Housing Boilers B008 (#1) and B009 (#2).....	15
Figure 5. Buildings 200-210 Gas-Fired Combustion Units	16
Figure 6. Buildings 45, 53, 80 and 81 Gas-Fired Combustion Units	17
Figure 7. Buildings 101 - 116 Gas-Fired Combustion Units	18
Figure 8. Buildings 150 - 158 Gas-Fired Combustion Units	19
Figure 9. Building 120 Gas-Fired Combustion Units	20

Attachments

Attachment 1 – SCR and SNCR Cost Workbooks and Cost Summary Spreadsheet
Attachment 2 – RACT Cost Workbook
Attachment 3 – NBW LNB Quote
Attachment 4 – Source Test Report for 2026 In-House Engineering Testing
Attachment 5 – Addendum for RACT Emissions Units Groupings
Attachment 6 – NOx Emissions Spreadsheets
Attachment 7 – RACT Implementation Schedule (Gantt Chart)

1. Executive Summary

This engineering study evaluates Reasonably Available Control Technology (RACT) for nitrogen oxides (NOx) emissions from combustion emission units located at the Howmet Aerospace facility in Cuyahoga Heights, Ohio, in accordance with Ohio Administrative Code (OAC) Rule 3745-110-03. The evaluation includes both the source-specific RACT determination for Boilers B008 and B009 and the engineering evaluation of other natural gas-fired combustion sources claiming exemption under OAC 3745-110-03(K). The study identifies each affected emission unit, evaluates the applicability of regulatory exemptions, evaluates technically feasible NOx control technologies, and determines whether additional controls satisfy the technical and economic criteria for RACT.

During preparation of this study, the Cleveland ozone nonattainment area was redesignated to attainment by the U.S. Environmental Protection Agency, with the final rule becoming effective on June 29, 2026.¹

The facility operates numerous natural gas-fired combustion sources that vary substantially in design, capacity, operating schedule, process function, and physical location throughout the manufacturing complex. These sources include process furnaces, heat treating equipment, ovens, dryers, comfort heating equipment, boilers, and other combustion devices that support diverse manufacturing operations. Because of these differences, the applicability of common emission controls and the feasibility of grouping multiple emission units for collective control must be evaluated on a case-by-case basis. This study incorporates detailed operating and emissions information for calendar years 2023 through 2025, operating data, annual NOx emissions, average daily NOx emissions, and maximum daily NOx emissions for each emission unit or permitted emission unit group subject to the RACT evaluation. The study also updates the regulatory applicability review to clarify the appropriate exemption basis for each emission unit and identifies the potential-to-emit for individual sources where emission units are subdivided for permitting purposes.

For emission units claiming exemption under OAC Rule 3745-110-03(K)(16), this study applies a weight-of-evidence evaluation to determine whether multiple emission units could reasonably be controlled collectively. The evaluation considers physical location, process function, operating schedules, combustion characteristics, exhaust system configuration, available control technologies, installation constraints, anticipated control effectiveness, and cost effectiveness. Where common control systems are determined to be technically or economically infeasible, the engineering basis for that conclusion is documented. Individual control technologies identified in OAC Rule 3745-110-03(J)(1)(h) are also evaluated for technical feasibility for the applicable categories of combustion sources.

For emission units not qualifying for regulatory exemption, this study follows the established top-down RACT methodology by identifying available NOx control technologies, evaluating technical feasibility, estimating achievable emission reductions, and assessing economic feasibility using EPA-recognized cost analysis methods. Where additional controls are determined to satisfy the requirements of OAC Rule 3745-110-03, the study identifies the recommended RACT alternative together with an implementation schedule consistent with Ohio EPA requirements.

Based upon the analyses presented herein, the study concludes that many combustion sources satisfy the applicability criteria for exemption under OAC Rule 3745-110-03(K) based on their individual emission characteristics and the engineering evaluations presented in this study. For those emission units requiring a full RACT evaluation, the recommended control strategy represents the lowest emission limitation that is both technically achievable and economically reasonable while maintaining reliable operation of the manufacturing processes served by each combustion unit.

¹ U.S. Environmental Protection Agency, *Air Plan Approval; Ohio; Redesignation of the Cleveland, OH Area to Attainment of the 2015 Ozone Standard*, 91 Fed. Reg. 39019–39027 (June 29, 2026) (FR Doc. 2026-13027), effective June 29, 2026.

1.1 Control Technology Evaluation

This study evaluates Reasonably Available Control Technology (RACT) for Boilers B008 and B009 using the top-down evaluation methodology contained in OAC Chapter 3745-110. The engineering evaluation included review of combustion modification technologies, post-combustion control technologies, representative engineering feasibility, vendor information, and comparative economic evaluations. The technologies retained for detailed evaluation consisted primarily of Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), and Low-NOx/Ultra-Low NOx Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR).

SCR and SNCR were evaluated as technically feasible post-combustion NOx control technologies for industrial boiler applications. The engineering evaluation determined that implementation of these technologies would require substantial retrofit integration, including major ductwork modifications, reagent handling systems, induced draft equipment, instrumentation, controls integration, and significant outage coordination. Comparative engineering and economic evaluations demonstrated that these technologies require substantially greater retrofit complexity and annualized cost than combustion-side control technologies for the subject boilers.

LNB/ULNB with integrated FGR was identified as the most appropriate combustion-side NOx control technology for Boilers B008 and B009. Vendor information demonstrates that replacement burner systems incorporating ultra-low NOx burners, induced flue gas recirculation, combustion controls, and associated balance-of-system modifications are technically capable of achieving substantial NOx reductions for the existing boiler configuration. The representative economic evaluation further demonstrated that this retrofit technology is economically reasonable for the subject boilers and represents the selected source-specific RACT technology.

In addition to the boiler-specific evaluation, the study evaluated the remaining forty-two natural gas-fired combustion sources using the representative engineering group methodology authorized under OAC 3745-110-03(K)(16). Representative engineering evaluations concluded that no centralized common-control technology represents a technically feasible and economically reasonable RACT alternative for these grouped combustion sources because of the diversity of combustion equipment, manufacturing processes, and facility configuration.

1.2 Proposed RACT Determination

Based on the engineering evaluations presented in this study, Howmet Aerospace proposes that source-specific RACT for Boilers B008 and B009 consist of installation of Low-NOx Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR), together with associated combustion controls, continued firing of natural gas, implementation of Good Combustion Practices, annual combustion tune-ups in accordance with OAC 3745-110-03(I), optimization of combustion system performance, and compliance with the applicable source-specific NOx emission limitation established through the final Ohio EPA RACT determination.

Recent stack testing performed during April 2026 measured baseline NOx emission rates of approximately 0.125 lb/MMBtu for Boiler B008 and approximately 0.149 lb/MMBtu for Boiler B009 under representative operating conditions. These measured emission rates served as the basis for the engineering evaluation and comparative economic analyses presented in this study. Vendor information indicates that the proposed LNB/ULNB with integrated FGR retrofit is capable of achieving substantially lower NOx emission rates following installation, startup, combustion tuning, and performance verification under specified operating conditions.

The selected RACT technology requires replacement of the existing burner systems together with installation of induced flue gas recirculation equipment, combustion controls, associated balance-of-system modifications, startup, commissioning, and post-installation performance verification. Consistent

with OAC 3745-110-04(B)(1), Howmet Aerospace will implement the approved RACT controls as expeditiously as practicable and no later than two years following the effective date of the final Ohio EPA RACT determination. A representative implementation schedule is presented in Section 12 of this study.

For the remaining grouped combustion sources, representative engineering evaluations demonstrated that centralized common-control technologies do not represent technically feasible and economically reasonable RACT alternatives. Accordingly, no additional representative common-control NOx technologies are proposed for the combustion-source groups evaluated under the representative engineering methodology.

Table 1-1. Summary of RACT Findings for Boilers B008 and B009

Item	B008	B009	RACT Finding/Engineering Rationale
Applicable Rule	OAC 3745-110-03 (B)	OAC 3745-110-03 (B)	Mid-size boilers (>50 to 100 MMBtu/hr)
Presumptive Limit	0.08 lb/MMBtu	0.08 lb/MMBtu	Serious ozone nonattainment presumptive limit.
April 2026 Test Result	0.125 lb/MMBtu	0.149 lb/MMBtu	Both units operate above the presumptive limit.
PTE-Based NOx Mass	64.91 TPY	64.91 TPY	Basis for comparative PTE cost-effectiveness evaluation
Most Effective Post-Combustion Control	SCR	SCR	Technically feasible in principle but associated with substantial retrofit complexity, flue gas temperature constraints, space limitations, and high annualized cost.
Selected RACT Technology	LNB/ULNB + Integrated FGR	LNB/ULNB + Integrated FGR	Technically feasible combustion retrofit; determined to be economically reasonable and selected as source-specific RACT
Representative Vendor Performance	~0.036 lb/MMBtu	~0.036 lb/MMBtu	Approximately 30 ppmvd @ 3% O ₂ (specified operating conditions)
Implementation Requirement	≤2 years	≤2 years	Per OAC 3745-110-04(B)(1)
Operational Measures	Natural gas, annual tune-ups, GCP, combustion optimization	Same	Continue following retrofit installation

In accordance with Ohio EPA regulations, Ohio EPA requested an analysis of the feasibility of controlling a grouping of exempt sources. The Addendum to this study evaluated the feasibility of SCR control of this group of sources and determined RACT was not feasible. Ohio EPA requested that additional controls be evaluated for the group or for subsets of the group based upon building locations and control options. That evaluation is summarized below and included in more detail in Section 11. Those units are summarized below in **Table 1-2**. Individual building groupings are found in **Tables 1-3 and 1-4**.

Table 1-2. Summary of Other Combustion Source Emission Units (Facility-Wide)

EU ID	Emission Unit Description	Rating (MMBtu/hr)	PTE (TPY)	RACT Exemption Basis
P100	Titanium Annealing Furnace T-8 - Building 206	22.2	9.53	OAC 3745-110-03(K)(16)
P125	Titanium Reheat Furnace T-9 - Building 206	18.6	8.00	OAC 3745-110-03(K)(16)
F027	T-10 Furnace - Building 206	13.98	6.00	OAC 3745-110-03(K)(16)
P162	27 MMBtu/hr direct gas-fired Inconel preheat furnace - Building. 206	27.0	11.59	OAC 3745-110-03(K)(16)
P177	120,000 lb SECO Ingot Soaking Furnace - Building 206	5.0	2.15	OAC 3745-110-03(K)(16)
P230	#6 Heat Treat Furnace - Building 206	9.0	3.86	OAC 3745-110-03(K)(16)
F023	R&S Reheat Furnace No. 1 - Building 206	12.0	5.15	OAC 3745-110-03(K)(16)
F024	R&S Reheat Furnace No. 3 - Building 206	12.0	5.15	OAC 3745-110-03(K)(16)
F025	No. 4 Salem Furnace - Building 206	13.8	5.93	OAC 3745-110-03(K)(16)
F026	No. 5 Salem Furnace - Building 206	13.8	5.93	OAC 3745-110-03(K)(16)
P107	6005 Reheat Furnace - Building 210	5.36	2.30	OAC 3745-110-03(K)(16)
P154	T-12 Titanium Preheat Furnace - Building 210	18.6	7.99	OAC 3745-110-03(K)(16)

EU ID	Emission Unit Description	Rating (MMBtu/hr)	PTE (TPY)	RACT Exemption Basis
P054	No. 5 H.T. Despatch Furnace	5.0	2.15	OAC 3745-110-03(K)(16)
P087	Titanium Reheat Furnace T-7	18.64	8.00	OAC 3745-110-03(K)(16)
P121-heat treat	South Heat Treat Oven - Building 150	12.98	11.37	OAC 3745-110-03(K)(16)
P121-age oven	South Age Oven - Building 150	13.5	Incl.	OAC 3745-110-03(K)(16)
P122-heat treat	North Heat Treat Oven - Building 150	9.25	5.69	OAC 3745-110-03(K)(16)
P122-age oven	North Age Oven - Building 150	4.0	Incl.	OAC 3745-110-03(K)(16)
P152-heat treat	Heat Treat Line #3 - Building 150	13.0	7.30	OAC 3745-110-03(K)(16)
P152-age oven	Heat Treat Line #3 - Building 150	4.0	Incl.	OAC 3745-110-03(K)(16)
P402	No. 13 Soaker Furnace - Building 150	16.75	7.19	OAC 3745-110-03(K)(16)
P003-heat treat	2502 Heat Treat Oven - Building 120	3.6	3.13	OAC 3745-110-03(K)(16)
P003-age oven	2502 Age Oven - Building 120	3.7	Incl.	OAC 3745-110-03(K)(16)
P004-heat treat	2503 Heat Treat Oven - Building 120	3.6	3.13	OAC 3745-110-03(K)(16)
P004-age oven	2503 Age Oven - Building 120	3.7	Incl.	OAC 3745-110-03(K)(16)
F003	2007 Furnace - Building 101	1.47	0.63	OAC 3745-110-03(K)(16)
F004	2502 Furnace - Building 101	0.5	0.21	OAC 3745-110-03(K)(16)
F006	4504 Furnace - Building 101	3.5	1.50	OAC 3745-110-03(K)(16)
F007	4505 Furnace - Building 101	3.5	1.50	OAC 3745-110-03(K)(16)
F008	4506 Furnace - Building 101	1.0	0.43	OAC 3745-110-03(K)(16)
F010	12001 Furnace - Building 111	12.0	5.15	OAC 3745-110-03(K)(16)
F011	12002 Furnace - Building 111	12.0	5.15	OAC 3745-110-03(K)(16)
F012	12003 Furnace - Building 111	12.0	0.00	Permanently shut-down (2025)
F015	12,000 Lb Reheat Furnace G-1	12.0	5.15	OAC 3745-110-03(K)(16)
F016	12,000 Lb Reheat Furnace G-2	12.0	5.15	OAC 3745-110-03(K)(16)
P434	6006 Preheat Furnace - Building 112A	3.6	1.55	OAC 3745-110-03(K)(16)
F018	2503 Preheat Furnace - Building 114	0.5	0.21	OAC 3745-110-03(K)(16)
P159	4601 Preheat Furnace - Building 114	3.6	1.55	OAC 3745-110-03(K)(16)
F017	2002 Preheat Furnace - Building 114	0.8	0.34	OAC 3745-110-03(K)(16)
F019	4509 Reheat Furnace - Building 114	8.0	3.44	OAC 3745-110-03(K)(16)
F020	4513 Reheat Furnace - Building 114	1.5	0.64	OAC 3745-110-03(K)(16)
P105	17001 Furnace	16.8	7.21	OAC 3745-110-03(K)(16)

The non-boiler natural gas-fired combustion sources were evaluated using a common-control feasibility approach that groups emission units according to physical location, process integration, and the practical ability to route exhaust to a shared emission control system. Boilers B008 and B009, located in Building 45, are subject to the source-specific RACT evaluation presented in this study and are evaluated separately. The remaining natural gas-fired furnaces and ovens are organized into common-control groupings based on plant location and engineering feasibility rather than solely by individual building designation.

The grouping methodology recognizes that many of the combustion sources are distributed among separate buildings or manufacturing areas, operate independently, and are not configured for collection by a common exhaust system. Most units discharge through individual local exhaust systems or direct exhaust arrangements that are not interconnected. As a result, implementation of common add-on controls would require multiple independent collection systems, extensive new ductwork, structural modifications, and separate control installations. Engineering evaluation indicates that common control would require four independent SCR systems together with substantial new exhaust collection infrastructure, resulting in very high capital cost and limited incremental environmental benefit. Accordingly, the grouped evaluation presented herein reflects the practical engineering limits of common-control implementation for the existing facility configuration.

Table 1-3. Common-Control Grouping Summary for Other Natural Gas-Fired Combustion Sources

Common-Control Group	Included Buildings / Areas	Units Included	Group PTE NOx (TPY)	2025 NOx (TPY)	Shared SCR Cost Effectiveness (\$/ton)	Ductwork / Capture Cost	RACT Grouping Determination
A-Plant Group	Buildings 206 and 210, plus related A-Plant furnaces	P100, P125, F027, P162, P177, P230, F023, F024, F025, F026, P107, P154, P054, P087	83.73	19.77	\$29,510	\$7,988,654	Grouped for common-control screening only; shared SCR is not economically reasonable considering cost effectiveness, extensive ductwork, fugitive/source capture needs, and plant layout.
S-Plant Group	Building 150	P121 heat treat, P121 age oven, P122 heat treat, P122 age oven, P152 heat treat, P152 age oven, P402	31.55	4.81	\$77,237	\$5,159,158	Grouped by location and similar heat-treat/age oven operations; common control is not economically reasonable.
Building 120 Group	Building 120	P003 heat treat, P003 age oven, P004 heat treat, P004 age oven	6.26	1.27	\$101,794	\$3,246,024	Small, low-emitting group with fugitive/non-ducted sources; common control is not economically reasonable.
H-Plant / Remaining Small Furnace Group	Buildings 101, 111, 112A, 114, and P105 area	F003, F004, F006, F007, F008, F010, F011, F012, F015, F016, P434, F018, P159, F017, F019, F020, P105	44.96	7.16	\$35,406	\$8,638,972	Common-control group used for screening; shared SCR is not economically reasonable due to low actual emissions, dispersed locations, and fugitive/non-ducted exhaust points.
Total - non-boiler groups	Facility-wide non-boiler natural gas-fired combustion sources	42 listed sources, excluding B008/B009 boilers	166.50	33.01	See groups above	>\$25,000,000	No common-control alternative is selected as RACT for the exempt/non-boiler source groupings.

The following clarifications apply to the common-control grouping evaluation:

- B008 and B009 are evaluated separately and are not included in the exempt/non-boiler common-control groupings.
- P162 is included in the A-Plant group for purposes of the common-control feasibility evaluation. Its current uncontrolled NOx potential to emit is 11.59 tons per year. Howmet proposes to accept an

enforceable NOx potential-to-emit limitation of less than 10 tons per year for P162 to establish eligibility under OAC 3745-110-03(K)(16).

- F011 is evaluated under the exemption provision in OAC 3745-110-03(K)(16).

For permitted emission units consisting of separate heat-treat and age-oven combustion components, the permitted combined NOx potential to emit was allocated between the individual components in proportion to rated heat input. The allocated values are used solely for common-control feasibility screening and do not represent separate permitted emission limits or independently established unit-specific potential-to-emit values.

Table 1-4. Unit Listing by Common-Control Group

Group	EU ID	Emission Unit Description	Rating (MMBtu/hr)	PTE NOx (TPY)	2025 NOx (TPY)	Notes / RACT Exemption Handling
A-Plant	P100	Titanium Annealing Furnace T-8 - Building 206	22.2	9.53	2.59	OAC 3745-110-03(K)(16)
A-Plant	P125	Titanium Reheat Furnace T-9 - Building 206	18.6	8.00	2.20	OAC 3745-110-03(K)(16)
A-Plant	F027	T-10 Furnace - Building 206	13.98	6.00	1.65	Fugitive source; OAC 3745-110-03(K)(16)
A-Plant	P162	27 MMBtu/hr direct gas-fired Inconel preheat furnace - Building 206	27.0	11.59	0.00	Howmet proposes an enforceable NOx PTE limit of less than 10 TPY to establish eligibility under OAC 3745-110-03(K)(16)
A-Plant	P177	120,000 lb SECO Ingot Soaking Furnace - Building 206	5.0	2.15	0.59	Below 10 MMBtu/hr; also <10 TPY OAC 3745-110-03(K)(16)
A-Plant	P230	#6 Heat Treat Furnace - Building 206	9.0	3.86	1.06	Below 10 MMBtu/hr; also <10 TPY
A-Plant	F023	R&S Reheat Furnace No. 1 - Building 206	12.0	5.15	1.41	Fugitive source; OAC 3745-110-03(K)(16)
A-Plant	F024	R&S Reheat Furnace No. 3 - Building 206	12.0	5.15	1.41	Fugitive source; OAC 3745-110-03(K)(16)
A-Plant	F025	No. 4 Salem Furnace - Building 206	13.8	5.93	1.63	Fugitive source; OAC 3745-110-03(K)(16)
A-Plant	F026	No. 5 Salem Furnace - Building 206	13.8	5.93	1.63	Fugitive source; OAC 3745-110-03(K)(16)
A-Plant	P107	6005 Reheat Furnace - Building 210	5.36	2.30	0.63	Below 10 MMBtu/hr; also <10 TPY OAC 3745-110-03(K)(16)
A-Plant	P154	T-12 Titanium Preheat Furnace - Building 210	18.6	7.99	2.19	OAC 3745-110-03(K)(16)
A-Plant	P054	No. 5 H.T. Despatch Furnace	5.0	2.15	0.59	Below 10 MMBtu/hr; also <10 TPY OAC 3745-110-03(K)(16)

Group	EU ID	Emission Unit Description	Rating (MMBtu/hr)	PTE NOx (TPY)	2025 NOx (TPY)	Notes / RACT Exemption Handling
A-Plant	P087	Titanium Reheat Furnace T-7	18.64	8.00	2.20	OAC 3745-110-03(K)(16)
S-Plant	P121 - heat treat	South Heat Treat Oven - Building 150	12.98	5.58	0.00	Allocated from the combined P121 permitted PTE based on rated heat input; used for common-control feasibility screening only; OAC 3745-110-03(K)(16)
S-Plant	P121 - age oven	South Age Oven - Building 150	13.5	5.79	0.00	Allocated from the combined P121 permitted PTE based on rated heat input; used for common-control feasibility screening only; OAC 3745-110-03(K)(16)
S-Plant	P122 - heat treat	North Heat Treat Oven - Building 150	9.25	3.97	1.35	Allocated from the combined P122 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
S-Plant	P122 - age oven	North Age Oven - Building 150	4.0	1.72	0.63	Allocated from the combined P122 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
S-Plant	P152 - heat treat	Heat Treat Line #3 - Building 150	13.0	5.59	1.71	Allocated from the combined P152 permitted PTE based on rated heat input; used for common-control feasibility screening only; OAC 3745-110-03(K)(16)
S-Plant	P152 - age oven	Heat Treat Line #3 Age Oven - Building 150	4.0	1.71	0.63	Allocated from the combined P152 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
S-Plant	P402	No. 13 Soaker Furnace - Building 150	16.75	7.19	1.71	OAC 3745-110-03(K)(16)

Group	EU ID	Emission Unit Description	Rating (MMBtu/hr)	PTE NOx (TPY)	2025 NOx (TPY)	Notes / RACT Exemption Handling
Building 120	P003 - heat treat	2502 Heat Treat Oven - Building 120	3.6	1.54	0.63	Allocated from the combined P003 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
Building 120	P003 - age oven	2502 Age Oven - Building 120	3.7	1.59	0.00	Allocated from the combined P003 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
Building 120	P004 - heat treat	2503 Heat Treat Oven - Building 120	3.6	1.54	0.63	Allocated from the combined P004 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
Building 120	P004 - age oven	2503 Age Oven - Building 120	3.7	1.59	0.00	Allocated from the combined P004 permitted PTE based on rated heat input; rated heat input is below 10 MMBtu/hr; OAC 3745-110-03(K)(16)
H-Plant / Remaining	F003	2007 Furnace - Building 101	1.47	0.63	0.13	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F004	2502 Furnace - Building 101	0.5	0.21	0.04	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F006	4504 Furnace - Building 101	3.5	1.50	0.00	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F007	4505 Furnace - Building 101	3.5	1.50	0.30	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F008	4506 Furnace - Building 101	1.0	0.43	0.09	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F010	12001 Furnace - Building 111	12.0	5.15	1.04	Fugitive source; OAC 3745-110-03(K)(16)
H-Plant / Remaining	F011	12002 Furnace - Building 111	12.0	5.15	1.04	OAC 3745-110-03(K)(16)
H-Plant / Remaining	F012	12003 Furnace - Building 111	12.0	0.00	0.00	Permanently shut down in 2025; final PTE should reflect shutdown status

Group	EU ID	Emission Unit Description	Rating (MMBtu/hr)	PTE NOx (TPY)	2025 NOx (TPY)	Notes / RACT Exemption Handling
H-Plant / Remaining	F015	12,000 lb Reheat Furnace G-1 - Building 111	12.0	5.15	1.04	Fugitive source; OAC 3745-110-03(K)(16)
H-Plant / Remaining	F016	12,000 lb Reheat Furnace G-2 - Building 111	12.0	5.15	1.04	Fugitive source; OAC 3745-110-03(K)(16)
H-Plant / Remaining	P434	6006 Preheat Furnace - Building 112A	3.6	1.55	0.39	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F018	2503 Preheat Furnace - Building 114	0.5	0.21	0.04	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	P159	4601 Preheat Furnace - Building 114	3.6	1.55	0.31	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F017	2002 Preheat Furnace - Building 114	0.8	0.34	0.00	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F019	4509 Reheat Furnace - Building 114	8.0	3.44	0.70	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	F020	4513 Reheat Furnace - Building 114	1.5	0.64	0.00	Below 10 MMBtu/hr; fugitive source OAC 3745-110-03(K)(16)
H-Plant / Remaining	P105	17001 Furnace	16.8	7.21	1.46	Fugitive source; OAC 3745-110-03(K)(16)

2. Facility Information

2.1 Name and Address

Howmet Aerospace Inc. – Cleveland Operations
1600 Harvard Avenue
Cuyahoga Heights, Ohio 44105

2.2 Owner Representative Information

Mr. Jonah Ross
Environmental Engineer
Howmet Aerospace – Cleveland Operations
1600 Harvard Avenue
Cuyahoga Heights, Ohio 44105
Phone: 412-418-5338

2.3 Study Approval Officer

Mr. Michael Lucek
Facilities Engineering Lead
Howmet Aerospace – Cleveland Operations
1600 Harvard Avenue
Cuyahoga Heights, Ohio 44105
Phone: 216-978-6442

2.4 Standard Industrial Classification (SIC/NAICS) and Source Classification Code (SCC)

NAICS Code: 332112 – Nonferrous Forging
SIC Code: 3463 – Nonferrous Forging
SCC: 10200602 – Natural gas-fired industrial boiler (package boiler)

2.5 General Source Information

2.5.1 Ohio EPA Application Number (PTI ID):

P0111267

2.5.2 Title V Permit Number:

P0135538

2.5.3 Facility Identification Number (Facility ID):

13-18-17-0314

2.5.4 Facility Longitudinal and Latitudinal Coordinates

41.447° North 81.677° West

2.5.5 Facility Location

Howmet Aerospace Inc. – Cleveland Operations is located in Cuyahoga Heights, Cuyahoga County, Ohio, within the former Cleveland ozone nonattainment area regulated under Ohio Administrative Code (OAC) Chapter 3745-110, but recently redesignated as attainment (see above).

The facility is an existing industrial manufacturing operation engaged primarily in metal forming and heat-treating activities supporting aerospace component production. Boilers B008 and B009 are located in Building 45 and provide steam generation for facility operations and process support.

The facility is located within the heavily industrialized Cuyahoga River valley corridor southeast of downtown Cleveland and is surrounded by longstanding industrial, transportation, rail, and manufacturing infrastructure. The surrounding area includes major steel manufacturing, metal processing, warehousing, rail operations, interstate transportation corridors, and other large industrial operations characteristic of the greater Cleveland industrial region. Boilers B008 and B009 are located within Building 45 near the central portion of the facility and discharge through existing permitted exhaust stacks associated with the facility steam generation system.

Figures 1-9 presented below identify the general facility location, surrounding area context, and the specific location of Boilers B008 and B009 and other combustion units and the buildings which house them within the facility.

Figure 1. Site Diagram of the Facility

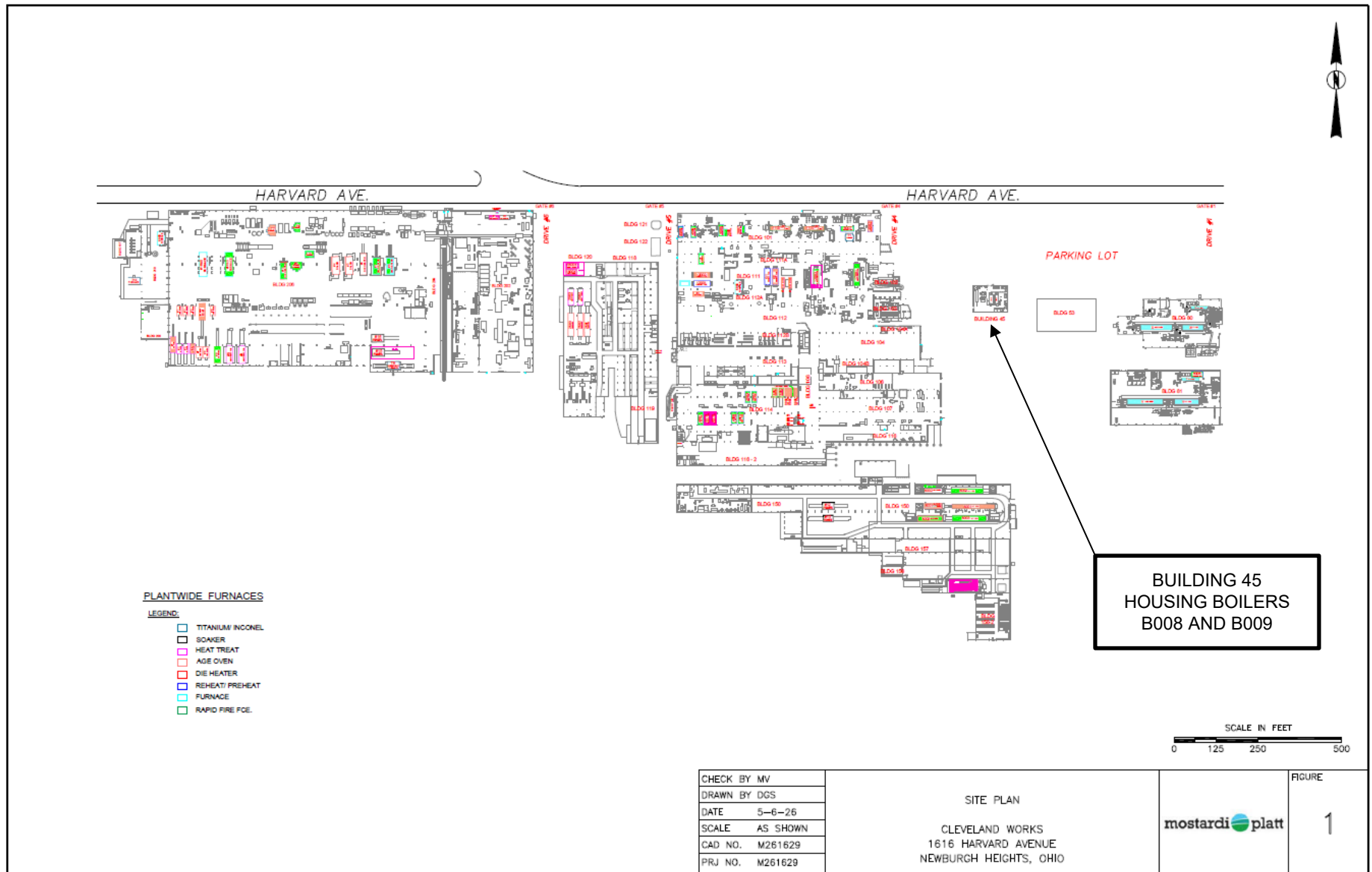


Figure 2. Aerial View of the Facility, with Boundary and Building 45 Location



Figure 3. Aerial View with Emission Units Call-Outs

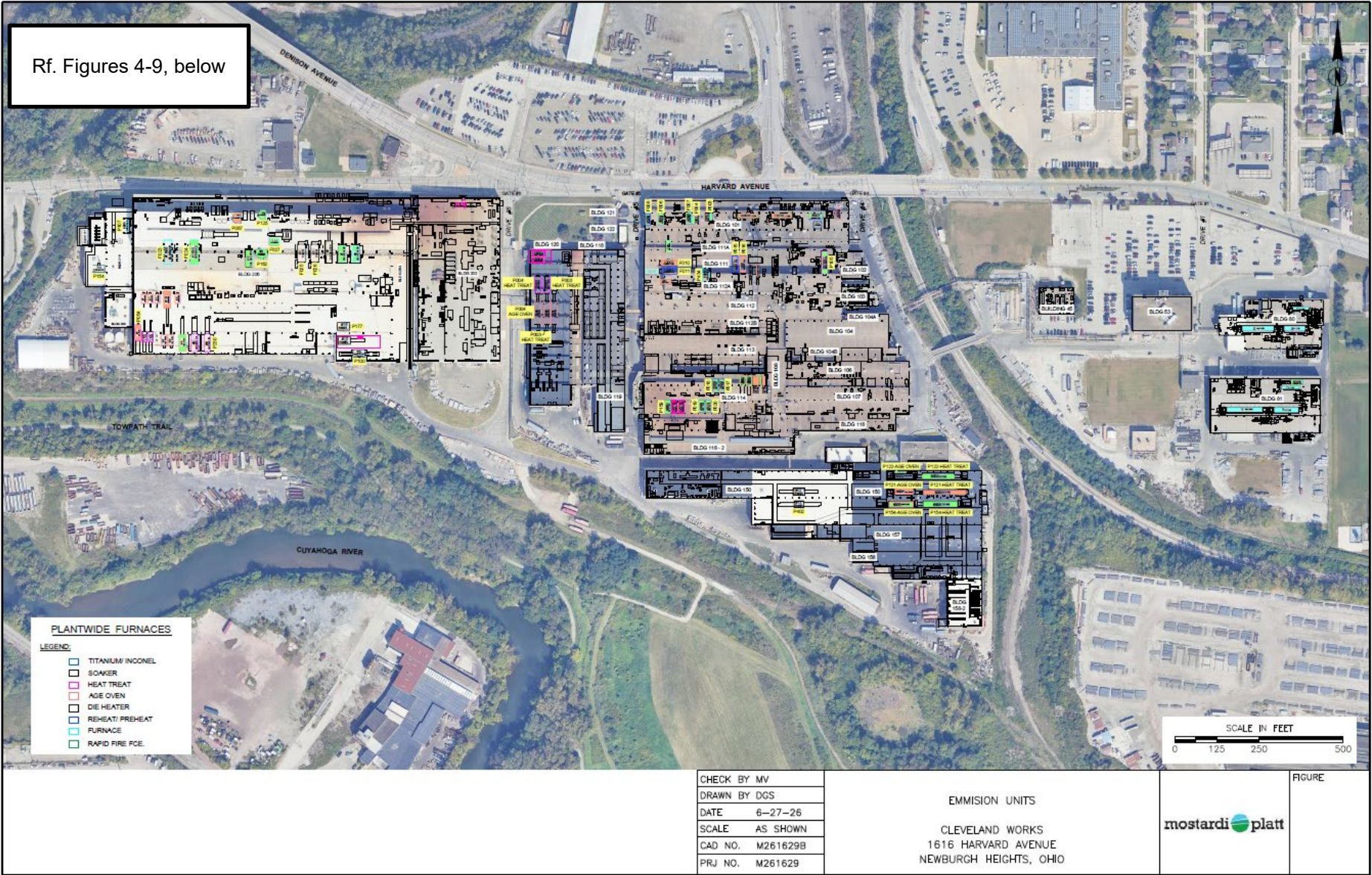


Figure 4. Building 45 Housing Boilers B008 (#1) and B009 (#2)

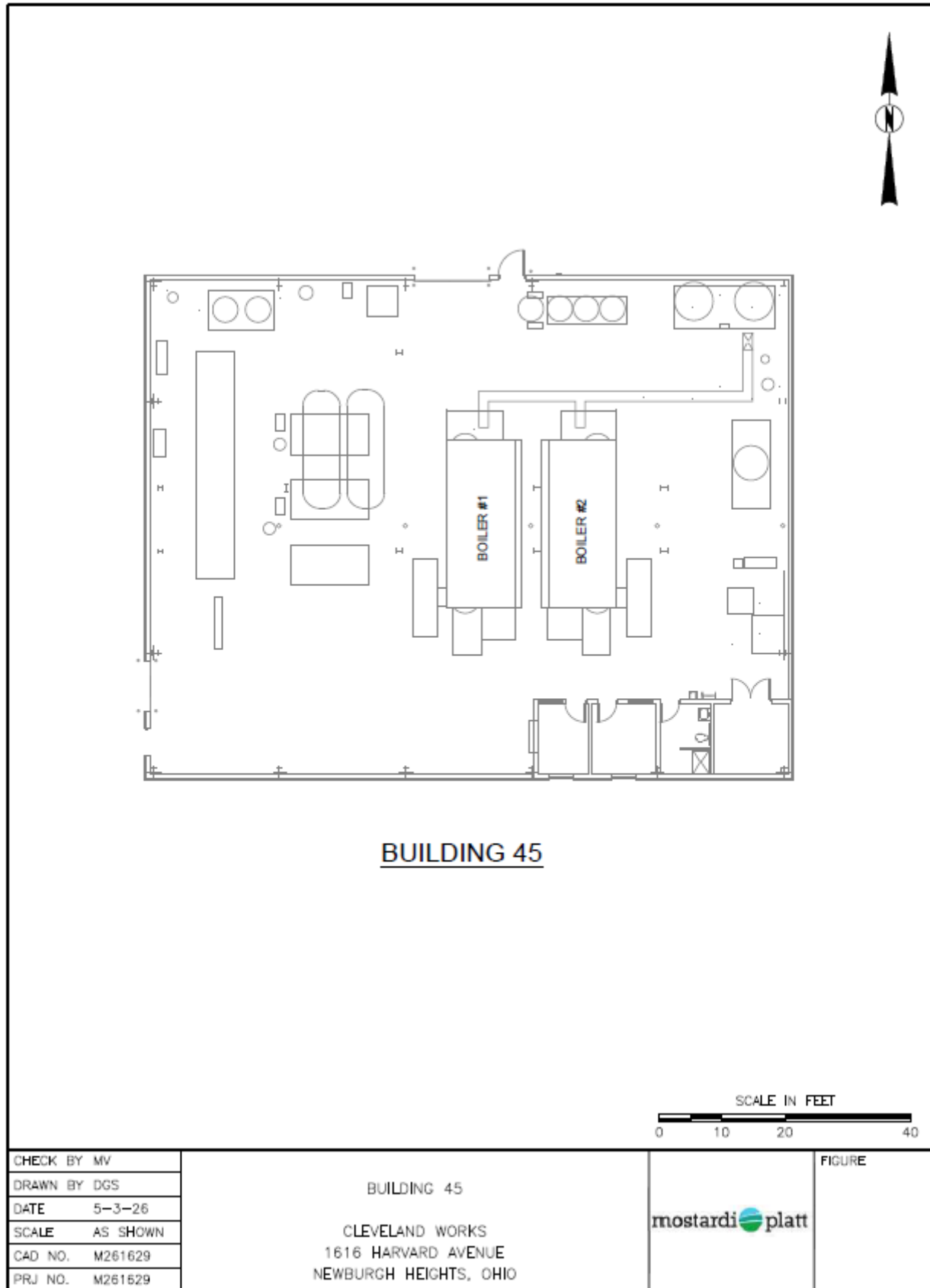


Figure 5. Buildings 200-210 Gas-Fired Combustion Units

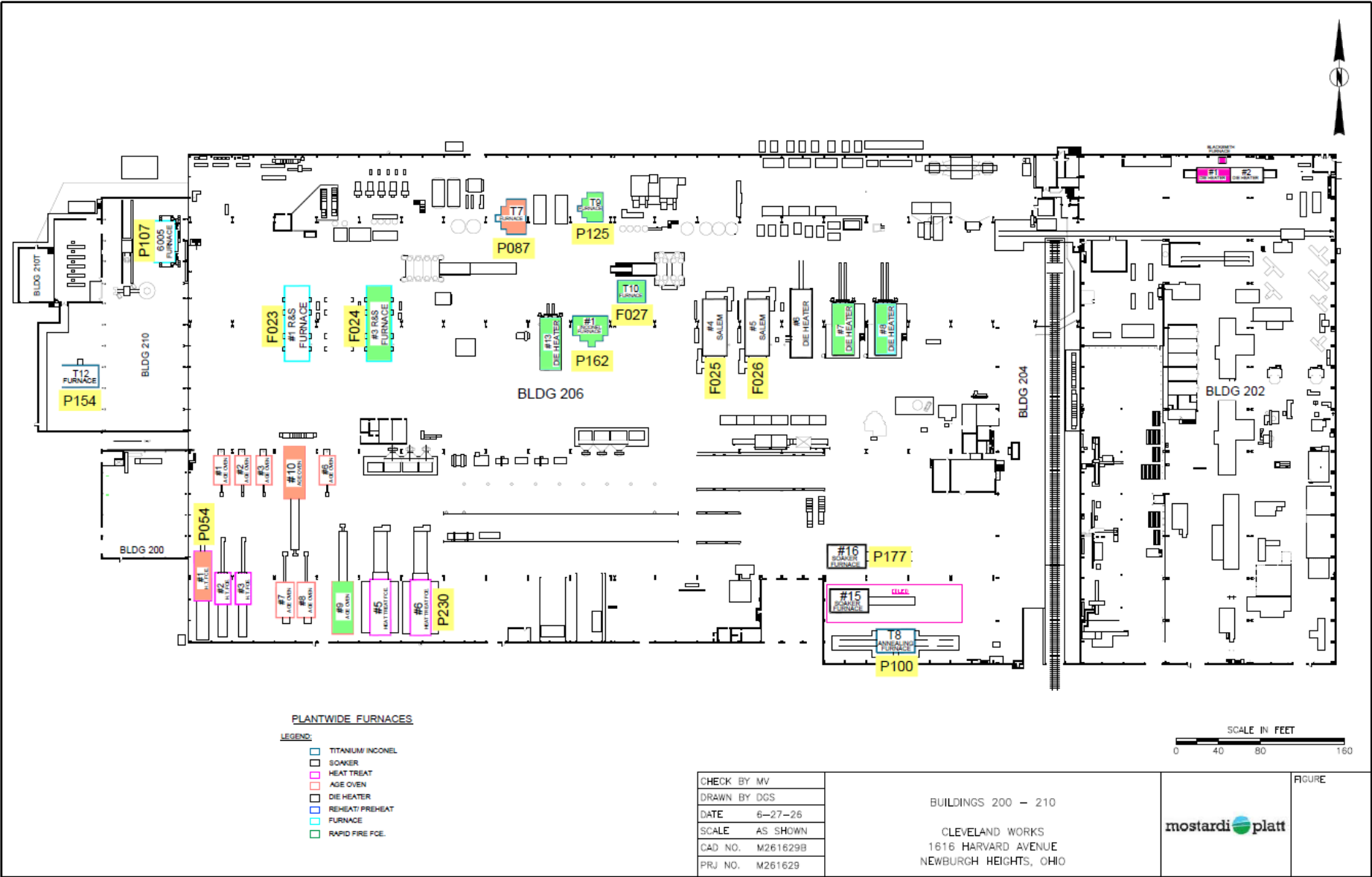


Figure 6. Buildings 45, 53, 80 and 81 Gas-Fired Combustion Units

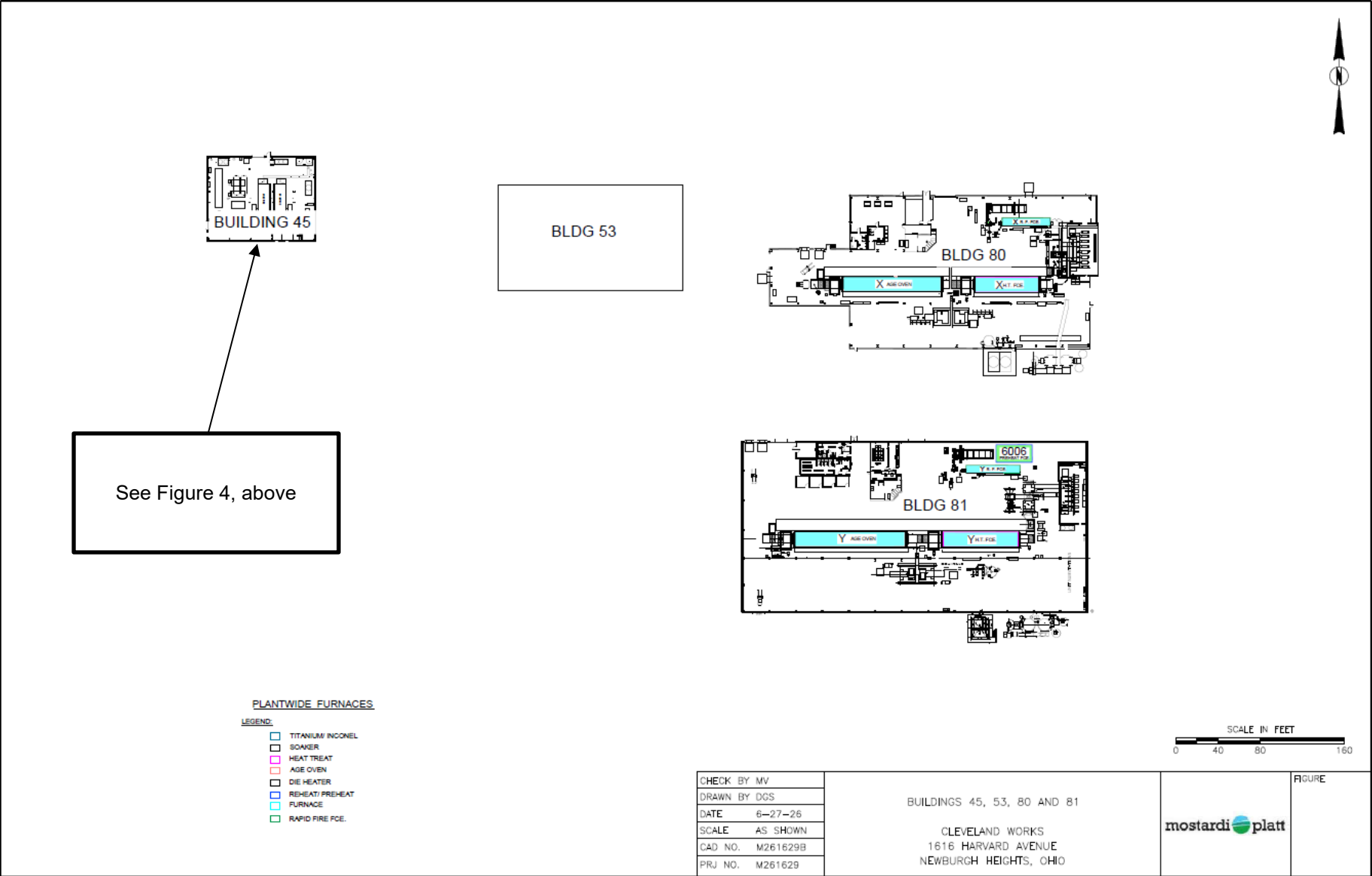


Figure 7. Buildings 101 - 116 Gas-Fired Combustion Units

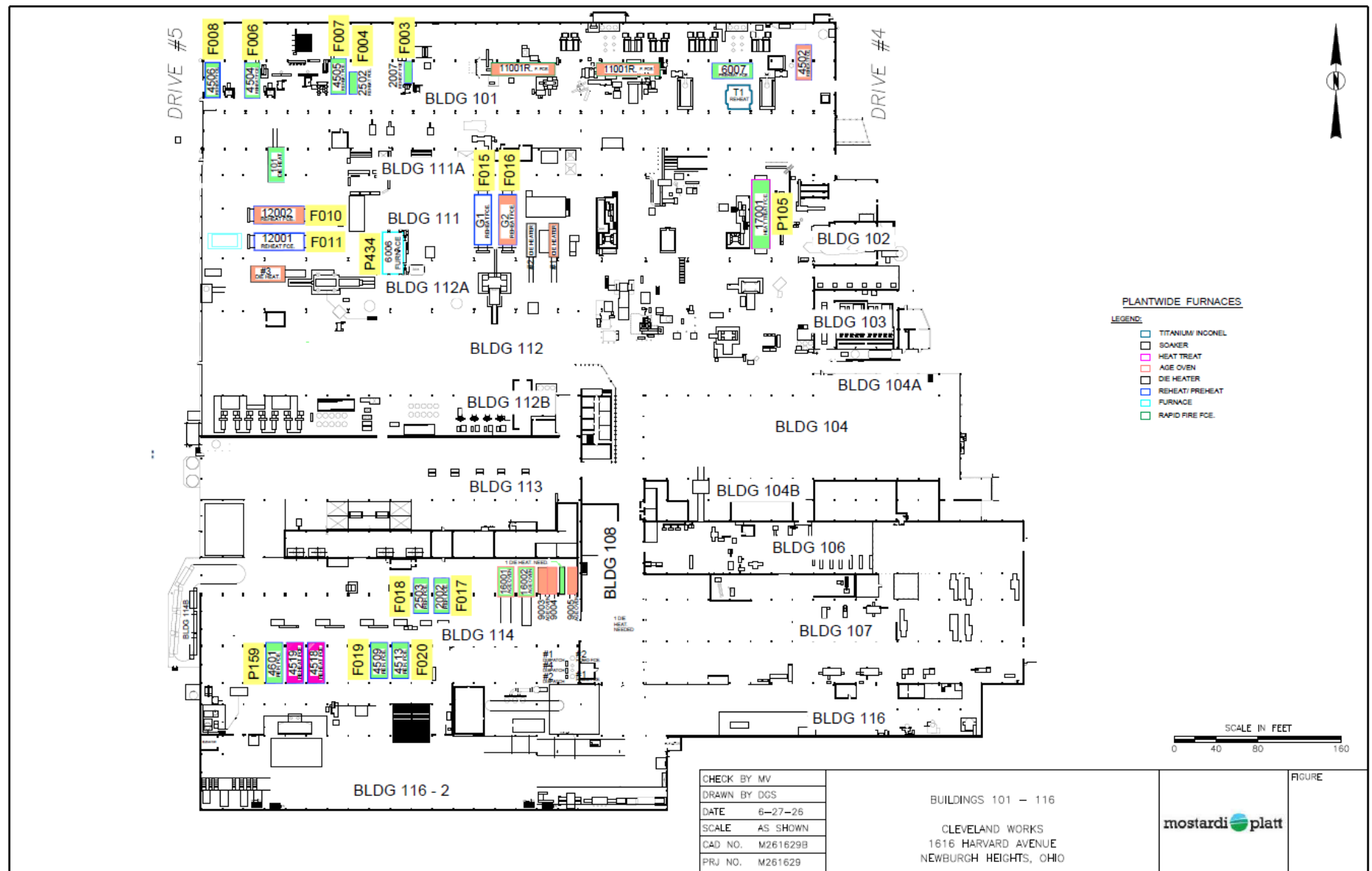


Figure 8. Buildings 150 - 158 Gas-Fired Combustion Units

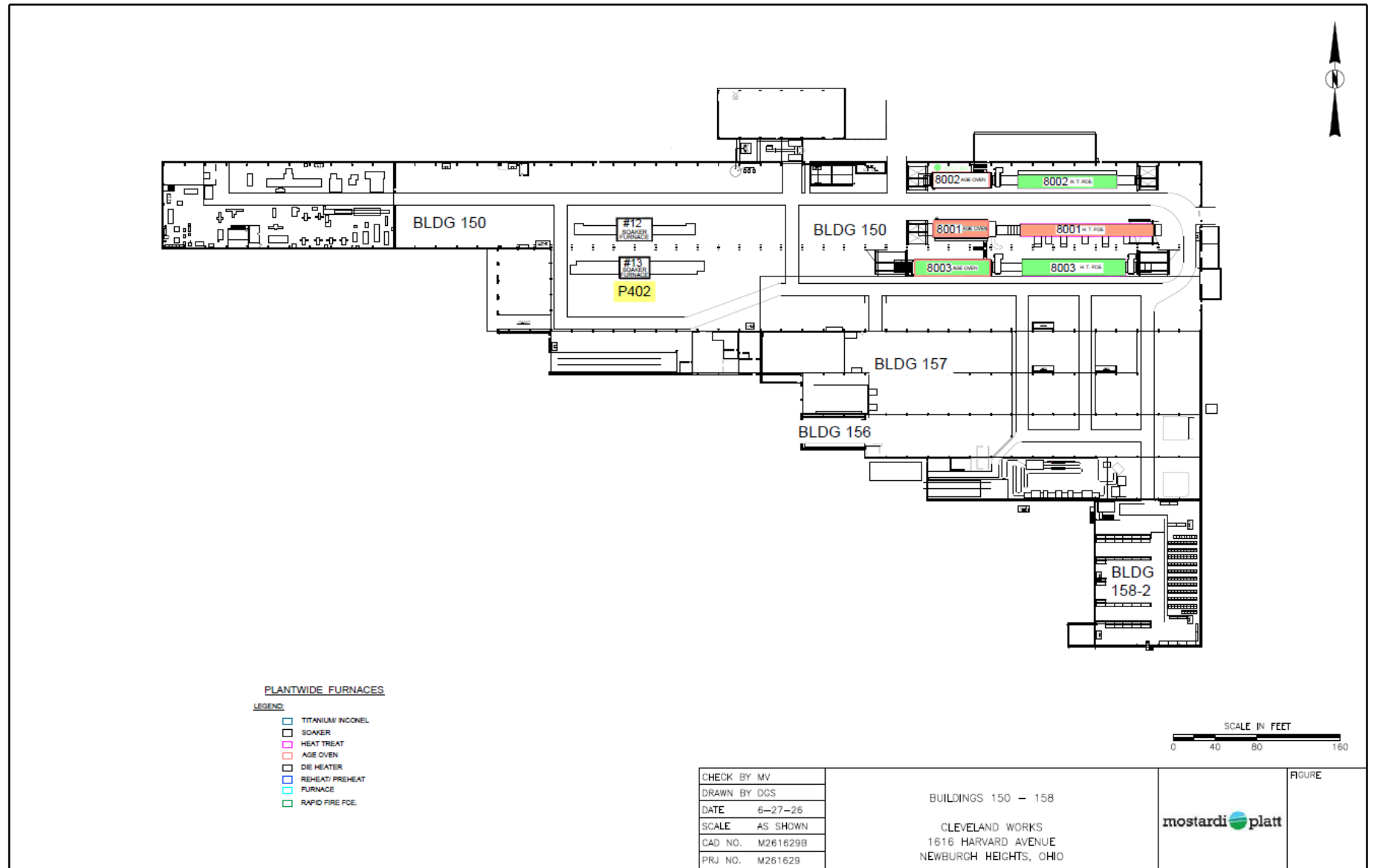
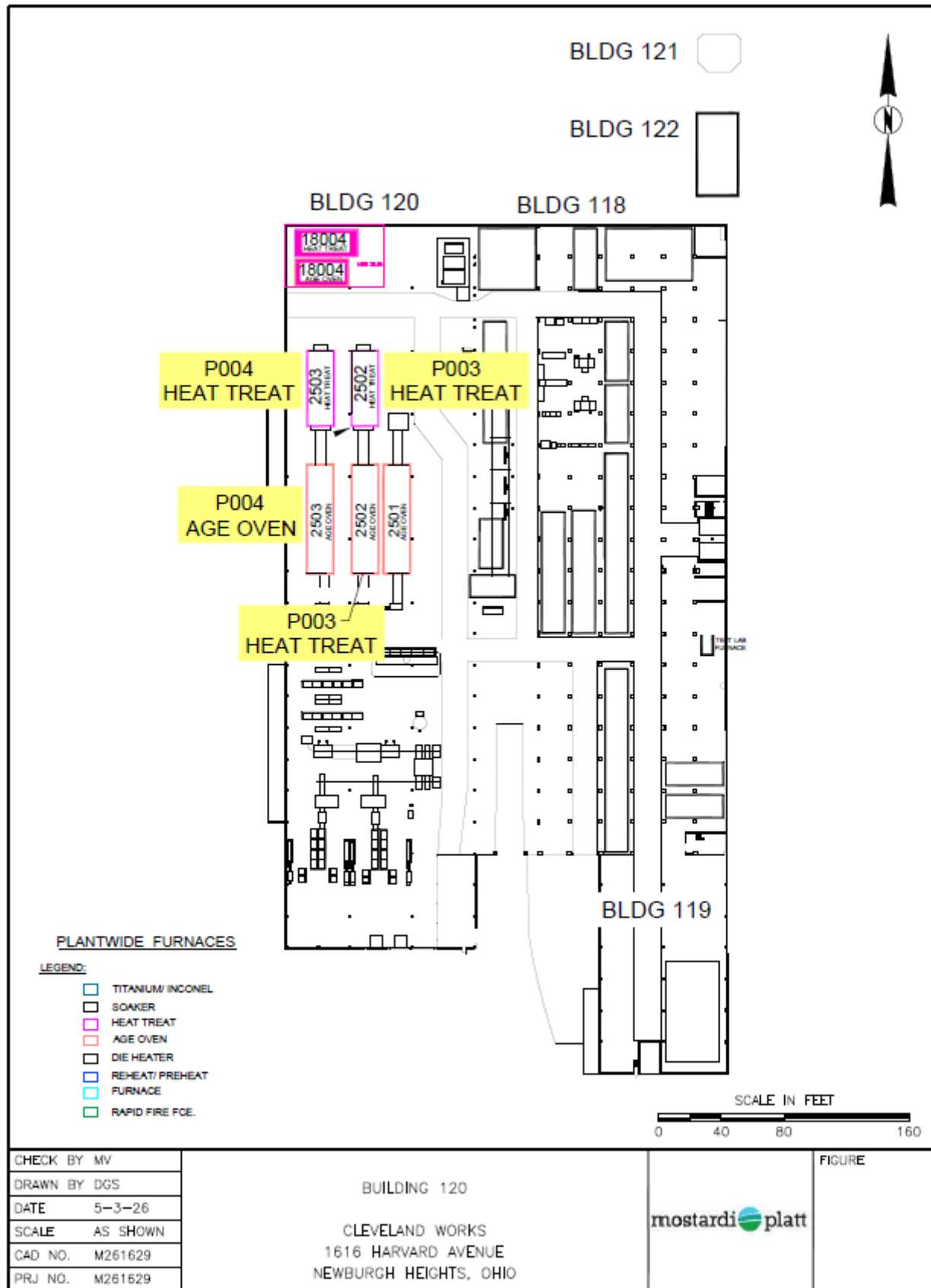


Figure 9. Building 120 Gas-Fired Combustion Units



3. Regulatory Framework and RACT Methodology

3.1 Ohio EPA NOx RACT Regulatory Framework

On January 16, 2025, the U.S. Environmental Protection Agency (U.S. EPA) reclassified the Cleveland, Ohio ozone nonattainment area (including Cuyahoga County) from "Moderate" to "Serious" for the 2015 8-hour ozone National Ambient Air Quality Standard (NAAQS), lowering the major stationary source threshold for NOx from 100 TPY to 50 TPY. Subsequently, U.S. EPA approved Ohio's request to redesignate the Cleveland area to attainment, with the final rule becoming effective on June 29, 2026.

This engineering study has been prepared in response to the Ohio EPA's ongoing review of the facility's NOx RACT evaluation and addresses the agency's requested revisions to the May 2026 RACT study. The revised rules expanded the applicability and stringency of NOx Reasonably Available Control Technology (RACT) requirements by:

- Extending NOx RACT applicability to additional geographic areas, including the Cincinnati region;
- Establishing more stringent emission limits for key source categories, including industrial, commercial, and institutional (ICI) boilers, stationary combustion turbines, and stationary internal combustion engines; and
- Eliminating prior exemptions from NOx RACT requirements for sources subject to the Cross-State Air Pollution Rule (CSAPR) or the NOx Budget Trading Program.

In accordance with OAC 3745-110-01(S), NOx RACT is defined as 'the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.' This definition provides the legal basis for the source-specific analysis conducted herein under OAC 3745-110-03(J).

This analysis acknowledges the following core principles established by the U.S. EPA and Ohio EPA:

- **Technological Feasibility:** A control is technically feasible if it has been demonstrated in practice or is available and applicable to the specific source type (98.8 MMBtu/hr package boiler). For Boilers B008 and B009, this includes an evaluation of the 1997 Nebraska package boiler furnace geometry, residence time, and the physical footprint of Building 45.
- **Economic Feasibility:** A control is economically feasible if the associated cost of NOx reduction is considered reasonable in relation to the magnitude of achievable emission reduction, retrofit complexity, operational impacts, and source-specific circumstances. Economic feasibility evaluations consider the relationship between achievable NOx reduction, retrofit complexity, operational impacts, combustion-system integration requirements, and the overall proportionality of the expected environmental benefit for the subject source. Ohio EPA has historically considered cost effectiveness as one factor within source-specific RACT evaluations, including review of annualized cost relative to achievable emission reductions.²
- **Alternative RACT Limits:** Per OAC 3745-110-03(J), where source-specific technical or economic considerations indicate that the presumptive limit may not be achievable or reasonable for the subject existing boilers, the owner/operator must propose an alternative RACT limit reflective of the most stringent level of control that is achievable for that specific unit.

Ohio EPA has established presumptive NOx RACT emission limits for mid-sized boilers (>50 to 100 MMBtu/hr) at 0.08 lb NOx/MMBtu. For sources where compliance with presumptive limits is technically infeasible or economically unreasonable, OAC 3745-110-03(J) requires the owner or operator to conduct a source-specific RACT analysis. Accordingly, this source-specific evaluation assesses available NOx control technologies in descending order of control effectiveness while considering technical feasibility, retrofit impacts, operational considerations, and economic reasonableness for the subject boilers.

² Ohio EPA, Division of Air Pollution Control, Response to Comments for Rule Package: OAC Chapter 3745-110 (NOx RACT), Response 2 (July 7, 2021).

A source-specific RACT analysis consistent with Ohio EPA expectations includes:

- A detailed process and emissions unit description;
- Identification and evaluation of all available NO_x control technologies, including combustion modifications and add-on controls (e.g., selective catalytic reduction [SCR] and selective non-catalytic reduction [SNCR]);
- A technical feasibility assessment to eliminate infeasible control options;
- A cost-effectiveness analysis, including capital costs, annual operating costs, and cost per ton of NO_x removed; and
- A RACT determination identifying the most appropriate control strategy and associated emission limitation.

Following the 2022 rule revisions, affected facilities were required to submit updated RACT analyses to Ohio EPA, typically within one year of the rule's effective date. Ohio EPA reviews such analyses and may establish site-specific RACT emission limits where appropriate, based on demonstrated technical and economic considerations.

Available facility operating information, annual fuel usage records, rolling emissions calculations, and operational day information for 2025 were reviewed as part of this analysis. Detailed production shift schedules and hourly operating schedules were not provided as part of the current study; however, the available operating and fuel usage information is considered sufficient to characterize representative boiler utilization and annual operating conditions for purposes of this source-specific RACT evaluation.

Based on facility-wide potential-to-emit and location within a designated ozone nonattainment area, the facility is subject to NO_x RACT requirements under OAC Chapter 3745-110.

3.2 Top-Down Methodology and Analysis Procedure

The RACT evaluation in this RACT analysis follows a top-down control technology framework commonly applied in RACT, Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) analyses. While RACT is less stringent than BACT or LAER because it explicitly considers technological and economic feasibility for existing sources, the top-down framework provides a structured and transparent approach for evaluating control options.

This study utilizes the U.S. EPA "Top-Down" methodology. Unlike a BACT analysis for new sources, this RACT analysis evaluates the technical constraints of retrofitting existing 1997-era equipment and the economic proportionality of the required investment.

The five steps are:

- Step 1. Identify All Available Control Technologies: A comprehensive search of the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), OEPA Engineering Guides, and vendor literature to identify every potential NO_x control measure.
- Step 2. Eliminate Technically Infeasible Options: Assessment of each technology against the physical and operational constraints of Boilers B008 and B009, including Building 45 footprint, furnace geometry, and flue gas temperature.
- Step 3. Rank Remaining Technologies by Effectiveness: Ranking based on potential NO_x reduction (lb/MMBtu).
- Step 4. Evaluate Economic, Environmental, and Energy Impacts: Calculation of the average cost-effectiveness using the procedures in the EPA Air Pollution Control Cost Manual. Cost effectiveness is evaluated using annual NO_x reductions developed from representative operating and emissions information consistent with OAC 3745-110-03(J)(1)(g) and (J)(1)(j). Potential-to-

emit (PTE) calculations are also presented as a sensitivity case to illustrate how higher theoretical utilization affects annual NOx reductions and calculated cost effectiveness..

- Step 5. Select RACT: Selection of the most stringent control that is both technically feasible and economically reasonable.

The evaluation follows a sequential top-down review process involving identification of potentially applicable NOx controls, technical feasibility screening, comparative effectiveness ranking, and economic evaluation. The remaining technologies are then ranked by control effectiveness and evaluated with respect to energy, environmental, and economic impacts. The final step is the selection of RACT as the most stringent control option that remains both technically feasible and economically reasonable.

The application of this framework to Boilers B008 and B009 is summarized in **Table 3-1**.

Table 3-1. Top-Down RACT Selection Methodology and Evaluation Criteria

Step	Task	Application to B008/B009
1	Identify all potentially available NOx control technologies	Comprehensive review of measures listed in OAC 3745-110-03(J)(1)(h), including combustion modifications, add-on post-combustion controls, and operational limitations.
2	Eliminate technically infeasible options	Screen for package boiler applicability, single-burner arrangement, natural-gas fuel, temperature window, residence time, reactor/injector location, fan/duct space, and operating reliability.
3	Rank remaining controls by control effectiveness	Rank based on expected NOx reduction and resulting annual TPY emissions.
4	Evaluate energy, environmental, and economic impacts	Estimate capital cost, O&M, annualized cost, NOx removed, cost effectiveness, outage burden, reagent handling, auxiliary power, and collateral effects, including pressure drop impacts, supplemental fuel or reheating requirements, ammonia slip potential, wastewater or reagent handling implications, secondary emissions, and effects on boiler reliability or efficiency.
5	Select RACT	Identify the most stringent control option that is both technically feasible and economically reasonable to achieve the presumptive limit of 0.08 lb/MMBtu. If source-specific technical or economic considerations indicate the presumptive limit may not be appropriate for the subject boilers, an alternative emission limit (AEL) is proposed.

No control technology identified during the initial screening process was excluded from consideration prior to completion of the technical and economic evaluations discussed in subsequent sections.

As with all retrofit evaluations involving existing combustion equipment, the conclusions presented herein are dependent upon currently available facility information, representative operating data, engineering assumptions, and practical retrofit considerations associated with maintaining ongoing facility operations.

For combustion sources evaluated under the exemption provisions of OAC Rule 3745-110-03(K), this methodology is supplemented by engineering evaluations of common-control feasibility and source-specific applicability, as discussed in subsequent sections of this report.

4. Process and Boiler Description

The facility is a metal forming and heat-treating operation located at 1600 Harvard Avenue, Cuyahoga Heights, Cuyahoga County, Ohio. The relevant Title V permit identifies Emissions Unit Group 1 as Gas Fired Boilers B008 and B009. The remaining natural gas-fired combustion sources evaluated in this study are integral components of the manufacturing process. Their operating schedules, firing rates, and production demands vary by process area and are not centrally controlled in a manner comparable to the facility boilers.

Table 4-1. Boiler Description and Permit-derived Engineering Baseline

Parameter	B008	B009	Source / use in analysis
Emission unit description	Boiler #1 – 98.8 MMBtu/hr gas-fired boiler, Building 45	Boiler #2 – 98.8 MMBtu/hr gas-fired boiler, Building 45	Title V Permit/OEPA AIRS Database.
Boiler type	Nebraska Boiler water-tube package boiler	Nebraska Boiler water-tube package boiler	Original Equipment Manufacturer (OEM) specs.
Installation date	August 1997	August 1997	Permit Records/Prior facility-specific 2011 RACT evaluation and combustion retrofit information for Boilers B008 and B009.
Fuel Usage	Natural gas, exclusively	Natural gas, exclusively	Title V Permit restriction.
Rated heat input	98.8 MMBtu/hr	98.8 MMBtu/hr	Basis for lb/hr and PTE calculations.
Process description	Steam generation for facility operations	Steam generation for facility operations	Facility process support boilers serving plant steam demand.
Operating schedule	Variable; steam demand drive.	Variable; steam demand driven.	Used to distinguish actual emissions from potential emissions.
Presumptive RACT limit	0.08 lb NOx/MMBtu	0.08 lb NOx/MMBtu	OAC 3745-110-03(B)
Historical emissions factor	0.15 lb NOx/MMBtu	0.15 lb NOx/MMBtu	2010 Stack Test/Current Permit Basis.
April 2026 stack test result	0.123–0.129 lb NOx/MMBtu	0.148–0.149 lb NOx/MMBtu	Recent stack testing used to evaluate current boiler performance and potential revised emission factors.
Current control equipment	Combustion controls and burner management only; no add-on post-combustion NOx controls identified	Combustion controls and burner management only; no add-on post-combustion NOx controls identified	Existing burner management systems.
Current permit restrictions	Natural gas-only firing pursuant to Title V operational restrictions	Natural gas-only firing pursuant to Title V operational restrictions	Title V permit operational restriction.
2025 annual NOx emissions	11.46 TPY	10.16 TPY	2025 annual emissions spreadsheet.
January-April 2026 NOx emissions	4.92 tons	2.87 tons	Current annual emissions spreadsheet.
Potential to Emit (PTE)	64.91 TPY	64.91 TPY	8,760 hours/year at 0.15 lb NOx/MMBtu and maximum rated heat input
Potential emissions basis	Heat input × emission factor × annual operating hours	Heat input × emission factor × annual operating hours	Used for comparative evaluation, sensitivity analysis, and supplemental RACT cost-effectiveness discussion.
Project-Specific Evaluation Objective	Representative Actual-Use Evaluation Basis — 2025 actual emissions and operating days used for primary cost-effectiveness evaluation; PTE retained as sensitivity case.	Representative Actual-Use Evaluation Basis — 2025 actual emissions and operating days used for primary cost-effectiveness evaluation; PTE retained as sensitivity case.	Representative actual-use operating conditions and PTE sensitivity cases used to evaluate technical feasibility, economic reasonableness, and comparative cost effectiveness of NOx control technologies.

4.1 Unit History and Baseline Performance

The Boilers (B008 and B009) are mid-sized, natural gas-fired package units installed in 1997 to replace legacy coal-fired equipment. Each unit has a rated capacity of 98.8 MMBtu/hr (approximately 80,000 lb/hr steam). As noted in the prior facility-specific 2011 RACT study³, these units serve facility-wide steam demand and do not have direct production-related emissions. Original engineering drawings and burner specifications from that period remain relevant for identifying the physical retrofit constraints inherent to the Building 45 footprint.

4.2 Analysis of April 2026 Stack Test Data

April 2026 stack testing (conducted at 90% load) confirms that while B008 and B009 operate consistently with historical factors, neither unit currently achieves the 0.08 lb/MMBtu presumptive limit.

Specifically, B008 operates at ~0.125 lb/MMBtu and B009 at ~0.149 lb/MMBtu. Because the testing was conducted at near-high-load conditions, these heat-input-normalized factors provide a robust and quantitative baseline for the following top-down analysis. This data is used to determine if further reductions are technically feasible or if the costs associated with achieving the presumptive limit are economically feasible under the site-specific conditions evaluated in this study.

4.3 Comparative Evaluation

The updated, heat-input-normalized emission factors derived from the April 2026 stack testing serve as the quantitative baseline for the Top-Down RACT analysis. This data confirms that while Boilers B008 and B009 are well-maintained and operate consistently with historical levels, neither unit achieves the 0.08 lb/MMBtu presumptive limit established under OAC 3745-110-03(B).

Consequently, this study must evaluate the feasibility of physical retrofits to bridge the performance gap between current operations (~0.15 lb/MMBtu) and the state's presumptive standard. The evaluation in the following sections emphasizes economic proportionality; specifically, whether the retrofit scope and associated capital investment required for Ultra-Low NOx Burners or SCR are reasonable for the subject existing boilers under representative operating conditions.⁴

By using actual performance data as the primary representative operating basis, while also retaining PTE as a sensitivity case, the study evaluates both current source-specific operating conditions and theoretical maximum-utilization conditions for purposes of the RACT cost-effectiveness review.

³ Prior facility-specific 2011 RACT evaluation and combustion retrofit information for Boilers B008 and B009, referenced in available project records and used in this study as historical engineering context.

⁴ For purposes of this study, intermittent utilization refers to the fact that the boilers do not operate continuously at full rated capacity throughout the year. Facility records indicate that Boiler B008 operated on 228 days in 2025 and Boiler B009 operated on 222 days in 2025, with remaining days reflecting standby or no-fuel-use conditions. This operating profile materially affects the annual NOx mass available for reduction and therefore affects calculated cost effectiveness for capital-intensive retrofit controls.

5. Baseline NOx Emissions and Representative Operating Basis

The 2025 emissions baseline is established using facility daily natural gas usage records, operating logs, and reported annual NOx emissions. This information provides the representative actual-use basis for evaluating annual NOx reductions and cost effectiveness under Step 4 of the top-down RACT analysis. The analysis also presents potential-to-emit (PTE) calculations as a sensitivity case to show how theoretical maximum utilization affects calculated cost effectiveness; however, the representative actual-use basis is the primary basis for evaluating the economic reasonableness of major retrofit controls for these boilers.

Natural gas usage reported in MCF (thousand standard cubic feet) for calendar year 2025 was converted to heat input using an assumed higher heating value (HHV) of 1020 Btu per standard cubic foot (scf), which is consistent with EPA standard assumptions for natural gas heating value used in emissions calculations. On this basis, 1 MCF (1000 scf) is equivalent to approximately 1.02 MMBtu.

5.1 Historical Annual Emissions and Operating Profile

Historical operating and emissions information for the three full calendar years preceding submission of this study (2023 through 2025) was reviewed to characterize representative boiler utilization and NOx emissions. **Table 5-1** summarizes annual NOx emissions together with operating and standby/down days for Boilers B008 and B009. The data indicate that the boilers operate intermittently in response to facility steam demand and are not continuously operated throughout the year.

Table 5-1. Historical Operational Baseline and Actual Emissions (2023 – 2025)

Year	Boiler ID	NOx (Tons)	Operating Days	Standby/Down Days
2023	B008	8.16	173	192
2023	B009	11.82	228	137
2024	B008	10.04	238	128
2024	B009	10.68	241	125
2025	B008	11.46	236	129
2025	B009	10.16	213	152

Note: Operating-day values for 2023 and 2024 are based on historical boiler-house operating records available for annual emissions reporting. Individual boiler-specific operating-day records were not available for the historical period; therefore, annual boiler-house operating days are presented for both units.

Table 5-2 summarizes annual NOx emissions on a combined facility basis. The data indicate that the boilers operate intermittently in response to facility steam demand and are not continuously operated throughout the year. Total annual NOx emissions from the two boilers remained relatively consistent during the three-year evaluation period.

Table 5-2. Historical Annual NOx Emissions Summary (2023 – 2025)

Year	B008 NOx (TPY)	B009 NOx (TPY)	Combined NOx (TPY)
2023	8.16	11.82	19.98
2024	10.04	10.68	20.71
2025	11.46	10.16	21.62

Annual Fuel Consumption Basis for EPA Cost Workbook Inputs

For purposes of completing the EPA SCR/SNCR cost workbooks, representative annual fuel consumption was derived from the 2025 actual NOx emissions baseline and the current 0.15 lb/MMBtu NOx performance basis. This approach avoids assuming 8,760-hour operation and reflects the actual intermittent operating profile of Boilers B008 and B009.

Formula:

$$\text{Annual Heat Input} = \frac{\text{NOx TPY} \times 2000}{0.15 \text{ lb NOx/MMBtu}}$$

$$\text{Annual Gas Use} = \frac{\text{Annual Heat Input}}{1.02 \text{ MMBtu/MCF}}$$

For B009:

$$10.16 \text{ TPY} \times 2000 = 20,320 \text{ lb NOx/yr}$$

$$20,320 / 0.15 = 135,467 \text{ MMBtu/yr}$$

$$135,467 / 1.02 = 132,811 \text{ MCF/yr}$$

$$132,811 \times 1000 = 132,811,000 \text{ scf/yr}$$

Therefore, the representative annual fuel consumption entered in the EPA workbook for B009 is:
132,810,000 scf/year

For B008, the same method gives:

$$11.46 \times 2000 / 0.15 = 152,800 \text{ MMBtu/yr}$$

$$152,800 / 1.02 = 149,804 \text{ MCF/yr}$$

$$149,804 \times 1000 = 149,804,000 \text{ scf/yr}$$

Therefore, the representative annual fuel consumption entered in the EPA workbook for B008 is:
149,800,000 scf/year

The study already supports this approach because it uses 2025 actual emissions and operating days as the primary cost-effectiveness basis, with PTE only as a sensitivity case.

5.2 Average vs. Maximum Daily Emissions

Pursuant to OAC 3745-110-03(J)(1)(g), average and maximum daily emissions are calculated to characterize the units' operational intensity. Average daily emissions were calculated using annual emissions and actual operating days for each year evaluated (2023 through 2025). Maximum daily emissions were calculated based on continuous 24-hour operation at the boiler rated capacity of 98.8 MMBtu/hr and the applicable NOx emission factor of 0.15 lb/MMBtu.

Table 5-3. Historical Estimated Average and Maximum Daily NOx Emissions (2023 – 2025)

Year	Boiler	Actual NOx (lb/day avg.)	Maximum Rated NOx (lb/day)
2023	B008	94.31	355.7
2023	B009	103.72	355.7
2024	B008	84.33	355.7
2024	B009	88.61	355.7
2025	B008	97.15	355.7
2025	B009	95.39	355.7

Note:

Average Daily: Calculated as (Tons x 2000)/Actual Operating Days

Maximum Daily: Based on 24-hour continuous operation at 98.8 MMBtu/hr and a 0.15 lb/MMBtu emission factor.

5.3 Potential to Emit (PTE)

Potential to Emit is presented as a comparative sensitivity case because it reflects theoretical maximum operation at rated capacity and the current 0.15 lb/MMBtu performance ceiling. The primary cost-effectiveness evaluation in this study uses representative actual emissions and operating information, with PTE retained to illustrate the effect of maximum theoretical utilization on calculated dollars-per-ton values.

- Baseline PTE (Per Boiler): 64.91 TPY
- Combined Facility Boiler PTE: 129.82 TPY

Maximum daily emissions were estimated based on a conservative “worst-case” scenario of continuous 24-hour operation at the rated capacity of 98.8 MMBtu/hr and the 0.15 lb/MMBtu performance ceiling.

5.4 Historical NOx Emissions Inventory for Remaining Natural Gas-Fired Combustion Sources

The remaining natural gas-fired combustion sources at the facility consist primarily of heat treat furnaces, aging ovens, process ovens, and small combustion units. **Table 5-4** summarizes the design heat input, potential NOx emissions, and representative average daily NOx emissions for calendar years 2023 through 2025. Boilers B008 and B009 are excluded because they are evaluated separately as the only emission units subject to the source-specific RACT analysis presented in this study. The information presented in **Table 5-4** provides the emissions inventory used in the common-control grouping and engineering feasibility evaluation discussed in the following section.

Table 5-4. Historical NOx Emissions Summary for Remaining Gas-Fired Combustion Sources (Average Daily NOx)

Emission Unit	Rating (MMBtu/hr)	PTE (TPY)	2023 Daily Avg. NOx Emissions (lb/day)	2024 Daily Avg. NOx Emissions (lb/day)	2025 Daily Avg. NOx Emissions (lb/day)
F018	0.5	0.21	0.33	0.27	0.24
F027	13.98	6.00	6.36	7.70	9.03
P054	5	2.15	2.25	2.73	3.23
P087	18.64	8.00	8.44	10.27	12.04
P100	22.2	9.53	9.97	12.13	14.20
P105	16.8	7.21	10.14	9.51	8.01
P107	5.36	2.30	2.41	2.95	3.46
P121 - heat treat	12.98	11.37	0.00	0.00	0.00
P121 - age oven	13.5		0.00	0.00	0.00
P122 - heat treat	9.25	5.69	7.62	7.27	7.42
P122 - age oven	4		0.00	0.00	0.00
P125	18.6	8.00	8.44	10.27	12.04
P152 - heat treat	13	7.30	9.75	9.34	9.52
P152 - age oven	4		0.00	0.00	0.00
P154	18.6	7.99	8.44	10.27	12.01
P159	3.6	1.55	2.19	2.02	1.72
P162	27	11.59	12.27	14.86	0.00
P177	5	2.15	2.25	2.73	3.23
P230	9	3.86	4.11	4.97	5.81

Emission Unit	Rating (MMBtu/hr)	PTE (TPY)	2023 Daily Avg. NOx Emissions (lb/day)	2024 Daily Avg. NOx Emissions (lb/day)	2025 Daily Avg. NOx Emissions (lb/day)
P402	16.75	7.19	9.64	9.23	9.38
P434	3.6	1.55	3.12	2.84	2.12
F003	1.47	0.63	0.88	0.82	0.70
F004	0.5	0.21	0.33	0.27	0.24
F006	3.5	1.50	2.14	1.97	0.00
F007	3.5	1.50	2.14	1.97	1.67
F008	1	0.43	0.60	0.55	0.48
F010	12	5.15	7.23	6.83	5.72
F011	12	5.15	7.23	6.83	5.72
F012	12	5.15	7.23	6.83	0.00
F015	12	5.15	7.23	6.83	5.72
F016	12	5.15	7.23	6.83	5.72
F017	0.8	0.34	0.00	0.00	0.00
F019	8	3.44	4.82	4.54	3.81
F020	1.5	0.64	0.00	0.00	0.00
F023	12	5.15	5.42	6.61	7.75
F024	12	5.15	5.42	6.61	7.75
F025	13.8	5.93	6.25	7.60	8.91
F026	13.8	5.93	6.25	7.60	8.91
P003 - heat treat	3.6	3.13	4.38	4.15	3.48
P003 - age oven	3.7		0.00	0.00	0.00
P004 - heat treat	3.6	3.13	4.38	4.15	3.48
P004 - age oven	3.7		0.00	0.00	0.00
Total Average NOx Emissions (lb/day)			186.9	200.3	183.5

Note: Totals shown for the remaining natural gas-fired combustion sources exclude Boilers B008 and B009, which are evaluated separately in this source-specific RACT analysis.

**Table 5-5. Historical NOx Emissions Summary for Remaining Gas-Fired Combustion Sources
(Tons of NOx Per Year)**

Emission Unit	Rating (MMBtu/hr)	PTE (TPY)	2023 NOx Emissions (Tons)	2024 NOx Emissions (Tons)	2025 NOx Emissions (Tons)
F018	0.5	0.21	0.06	0.05	0.04
F027	13.98	6.00	1.16	1.41	1.65
P054	5.0	2.15	0.41	0.50	0.59
P087	18.64	8.00	1.54	1.88	2.20
P100	22.2	9.53	1.82	2.22	2.59
P105	16.8	7.21	1.85	1.74	1.46
P107	5.36	2.30	0.44	0.54	0.63

Emission Unit	Rating (MMBtu/hr)	PTE (TPY)	2023 NOx Emissions (Tons)	2024 NOx Emissions (Tons)	2025 NOx Emissions (Tons)
P121 - heat treat	12.98	11.37	0.00	0.00	0.00
P121 - age oven	13.5				
P122 - heat treat	9.25	5.69	1.39	1.33	1.35
P122 - age oven	4.0				
P125	18.6	8.00	1.54	1.88	2.20
P152 - heat treat	13.0	7.30	1.78	1.71	1.74
P152 - age oven	4.0				
P154	18.6	7.99	1.54	1.88	2.19
P159	3.6	1.55	0.40	0.37	0.31
P162	27.0	11.59	2.24	2.72	0.00
P177	5.0	2.15	0.41	0.50	0.59
P230	9.0	3.86	0.75	0.91	1.06
P402	16.75	7.19	1.76	1.69	1.71
P434	3.6	1.55	0.57	0.52	0.39
F003	1.47	0.63	0.16	0.15	0.13
F004	0.5	0.21	0.06	0.05	0.04
F006	3.5	1.50	0.39	0.36	0.00
F007	3.5	1.50	0.39	0.36	0.30
F008	1.0	0.43	0.11	0.10	0.09
F010	12.0	5.15	1.32	1.25	1.04
F011	12.0	5.15	1.32	1.25	1.04
F012	12.0	5.15	1.32	1.25	0.00
F015	12.0	5.15	1.32	1.25	1.04
F016	12.0	5.15	1.32	1.25	1.04
F017	0.8	0.34	0.00	0.00	0.00
F019	8.0	3.44	0.88	0.83	0.70
F020	1.5	0.64	0.00	0.00	0.00
F023	12.0	5.15	0.99	1.21	1.41
F024	12.0	5.15	0.99	1.21	1.41
F025	13.8	5.93	1.14	1.39	1.63
F026	13.8	5.93	1.14	1.39	1.63
P003 - heat treat	3.6	3.13	0.80	0.76	0.63
P003 - age oven	3.7				
P004 - heat treat	3.6	3.13	0.80	0.76	0.63
P004 - age oven	3.7				

5.5 Emission Unit P162 Applicability Determination

Emission Unit P162 is not currently exempt from the applicability requirements of OAC 3745-110 because its existing permit does not establish an enforceable limitation restricting potential NO_x emissions to less than 10 tons per year. However, the unit is capable of operating below this threshold based on its design heat input, fuel characteristics, and anticipated operating profile.

Accordingly, Howmet intends to submit an application to modify Permit to Install (PTI) No. P0111267 to establish an enforceable 12-month rolling natural gas usage limitation for Emission Unit P162 that limits potential NO_x emissions to less than 10 tons per year. Upon issuance of the modified PTI, P162 would satisfy the exemption provided in OAC 3745-110-03(K)(16). Because the modified PTI will establish a federally enforceable permit limitation restricting potential NO_x emissions below the regulatory applicability threshold, Emission Unit P162 is not included in the RACT evaluation presented in this study.

6. Identification of Available Control Technologies

In accordance with OAC 3745-110-03(J)(1)(h), a comprehensive review was conducted to identify all potentially applicable NO_x control technologies for Boilers B008 and B009. The review included the full range of control measures identified in Ohio EPA guidance and prior approved NO_x RACT studies, including combustion modification controls, post-combustion controls, operational controls, and fuel-based control approaches. Certain technologies identified in the rule are inherently not applicable to natural gas-fired package boilers or are intended for other combustion source categories such as combustion turbines, internal combustion engines, or process kilns. The remaining potentially applicable technologies were further evaluated using the top-down RACT methodology described in Section 4.

Also, this section evaluates whether the remaining natural gas-fired combustion sources can reasonably be grouped for application of common NO_x control systems. The evaluation is based on engineering considerations including physical location, process function, operating schedules, existing exhaust configurations, constructability, and economic feasibility. The objective is to determine whether common emission controls are technically and economically feasible for groups of similar combustion sources or whether separate control strategies are more appropriate based on the design and operation of the individual process areas.

6.1.1 Engineering Evaluation Methodology for Remaining Natural Gas-Fired Combustion Sources

The remaining natural gas-fired combustion sources were evaluated to determine whether multiple emission units could reasonably be combined for application of common NO_x control technologies. Rather than relying solely on permit numbering or administrative emission-unit designations, the evaluation was based on the physical arrangement of the facility, process integration, and the practical feasibility of collecting exhaust gases for treatment by a common emission control system.

Engineering groupings were developed using facility layout drawings, process locations, equipment functions, and the physical arrangement of the combustion sources throughout the Cleveland Works manufacturing complex. The primary grouping criteria included: (1) physical proximity of combustion units; (2) location within the same manufacturing building or process area; (3) similarity of process function; (4) operating schedules; (5) existing exhaust configurations; (6) compatibility of exhaust temperatures and gas characteristics; and (7) the practical feasibility of installing common ductwork and centralized NO_x control equipment.

Based on these criteria, the combustion sources naturally segregate into several major manufacturing areas. Buildings 101 through 116 contain numerous reheat furnaces, die heaters, age ovens, and heat-treat furnaces supporting the primary forging operations. Buildings 118 through 122 contain a separate cluster of heat-treat furnaces and age ovens serving another production area. Buildings 200 through 210 contain multiple heat-treat, age, rapid-fire, die-heater, titanium, and Inconel furnaces that operate within a separate manufacturing complex. Building 150 contains a comparatively isolated group of heat-treat and soaker furnaces. Boilers B008 and B009 are located within Building 45 and continue to be evaluated separately because they function as utility steam-generating equipment rather than process furnaces.

The engineering evaluation considered whether combustion sources within each manufacturing area could reasonably be connected to a common NO_x control system. This evaluation extended beyond simple physical distance and considered the routing of large-diameter ductwork through active production areas, structural interferences, process equipment, cranes, utilities, fire protection systems, and ongoing manufacturing operations. The evaluation also considered the need to maintain adequate draft control for each combustion source, differences in exhaust temperatures and flow rates, process operating schedules, shutdown requirements, and the operational impacts associated with connecting multiple independent furnaces to a centralized exhaust collection system.

Although several combustion sources are located within the same general manufacturing area, many operate as individually exhausted process units designed for independent production operations.

Collecting exhaust from multiple furnaces would require extensive ductwork modifications, structural steel, induced-draft fans, dampers, controls integration, and significant modifications to existing exhaust systems. Such modifications would require substantial construction within active manufacturing areas and would likely necessitate extended production outages during installation.

For these reasons, the engineering evaluation focused on representative common-control groupings based on manufacturing area rather than evaluating each combustion source independently. These groupings provide a practical engineering framework for evaluating the technical feasibility and economic reasonableness of centralized NO_x control technologies while recognizing the physical constraints of the existing facility. The individual control technologies identified in OAC Rule 3745-110-03(J)(1)(h) are evaluated in the following sections with respect to these representative engineering groups and the specific characteristics of the subject combustion sources.

Table 6-1 summarizes the representative engineering groupings developed for evaluation of common NO_x control feasibility for the remaining natural gas-fired combustion sources. The groupings are based on physical location, manufacturing function, and the practical feasibility of implementing centralized emission controls rather than administrative permit designations. These representative groupings provide the framework for the technical and economic evaluations presented in the following sections.

Table 6-1. Representative Engineering Grouping of Remaining Natural Gas-Fired Combustion Sources for Common-Control Evaluation

Engineering Group	Building(s)	Representative Emission Units*	Primary Process Function	Basis for Grouping
Group 1 – A-Plant	Buildings 200, 206, 210	P100, P125, F027, P162, P177, P230, F023–F026, P107, P154, P054, P087	Titanium processing, Inconel processing, reheat furnaces, die heaters, preheat furnaces, soaking furnaces	Common manufacturing area with related forging and process heating operations.
Group 2 – S-Plant	Building 150	P121, P122, P152, P402	Heat-treat furnaces, age ovens, soaker furnace	Dedicated heat-treatment manufacturing area with independent exhaust systems.
Group 3 – Building 120	Building 120	P003, P004	Heat-treat furnaces and age ovens	Self-contained manufacturing area with common process function.
Group 4 – H-Plant / Remaining Small Furnaces	Buildings 101, 111, 112, 114	F003, F004, F006–F020, P105, P159, P434	Reheat furnaces, preheat furnaces, process furnaces	Distributed process combustion sources serving common manufacturing operations with independent exhaust systems.
Separate Evaluation	Building 45	B008, B009	Package boilers	Evaluated separately under the source-specific top-down RACT analysis.

* Representative emission units are shown for illustration of the engineering groupings. The complete inventory of combustion sources evaluated within each group is presented in the facility emissions inventory tables and associated engineering drawings.

6.1.2 Operational and Combustion Optimization Controls

- **Low-Excess Air (LEA) Optimization:** LEA reduces NO_x formation by limiting excess oxygen in the combustion zone, which minimizes thermal NO_x production. This strategy is highly applicable to natural gas-fired package boilers. The available information indicates that the boilers are equipped with combustion controls and burner management systems; however, the specific extent to which low-excess-air optimization is currently implemented has not been independently verified in this study. This option is retained as a technically feasible combustion optimization measure. This option is retained.
- **Air/Fuel Ratio Adjustment:** This strategy manually balances fuel and air to maintain stable flame conditions and minimize localized high-temperature zones. It is a standard operational practice for industrial boilers. Air/fuel ratio adjustment is a standard boiler combustion optimization practice. Available information indicates the presence of combustion controls and burner management systems; however, specific current operating settings and optimization practices should be confirmed through facility records, tune-up documentation, or operator review. This option is retained as a technically feasible operational control measure.
- **Fuel/Air Controls Modernization:** This approach involves installing automated electronic control systems to dynamically adjust the fuel-to-air ratio based on real-time exhaust measurements. This technology is technically feasible and is retained for further economic evaluation.

6.1.3 Combustion Modification Technologies

- **Low NO_x Burners (LNB) and Ultra-Low-NO_x Burners (ULNB):** These burners restrict NO_x formation through staged fuel or air combustion, which reduces peak flame temperatures and localized oxygen concentrations. These systems are widely demonstrated on industrial package boilers of this scale. This option is retained as a technically feasible combustion control.
- **Flue Gas Recirculation (FGR):** FGR recirculates a portion of the relatively cool flue gas back into the burner's combustion air supply, which lowers the flame temperature and dilutes the oxygen concentration. FGR is generally applicable to water-tube boilers. It is retained for economic evaluation.
- **Integrated ULNB + Induced FGR + Advanced Controls:** This combined approach bundles burner replacement, forced-draft fan modifications, induced FGR ductwork, and digital burner management system upgrades into a single retrofit project. This constitutes the highest-confidence combustion-side modification for package units. This option is retained.

6.1.4 Post-Combustion Control Systems

- **Selective Catalytic Reduction (SCR):** SCR injects an ammonia-based reagent into the exhaust stream upstream of a catalyst bed to chemically reduce NO_x into elemental nitrogen and water. Effective reduction typically requires a flue gas temperature window between 500°F and 800°F. The reported stack temperatures for Boilers B008 and B009 are approximately 400°F, which sits below the optimal catalyst window. Available information indicates that SCR implementation would likely require significant design accommodations associated with flue gas temperature management, duct routing, and available installation space within Building 45. However, it is retained for economic screening as the top-ranked control option.
- **Selective Non-Catalytic Reduction (SNCR):** SNCR injects ammonia or urea directly into the boiler furnace to reduce NO_x without a catalyst. This chemical reaction requires a narrow temperature window between 1,600°F and 2,100°F and sufficient residence time. Because Boilers B008 and B009 are compact, mid-sized package units with limited available furnace residence volume and relatively low downstream exhaust temperatures, available information does not demonstrate the presence of a suitable and maintainable high-temperature reaction zone necessary to support reliable SNCR performance. Accordingly, SNCR was not identified as a technically viable retrofit option for the subject boilers and is retained in the record for completeness of the RACT evaluation.
- **Non-Selective Catalytic Reduction (NSCR):** NSCR utilizes a three-way catalyst system to simultaneously reduce NO_x, carbon monoxide, and hydrocarbons. This reaction requires a rich-

burn environment with near-zero exhaust oxygen concentrations. Because industrial boilers operate under lean-burn, oxygen-rich conditions, NSCR cannot function. NSCR is technically infeasible and is eliminated.

- Ammonia Injection: This refers to the standalone use of ammonia gas injection without secondary catalytic or non-catalytic processing. Independent ammonia injection cannot reduce NO_x outside the high-temperature SNCR window or without an SCR catalyst. Standalone ammonia injection is technically infeasible and is eliminated.

6.1.5 Incompatible Source-Category and Fuel-Based Controls

- Close-Coupled Overfire Air (COFA): COFA routes a portion of the combustion air to ports situated directly above the primary burner zone to stage combustion. This strategy is designed exclusively for large, multi-burner coal-fired utility boilers or large stoker units. It cannot be adapted to single-burner gas-fired package units. This option is technically infeasible and is eliminated.
- Separated Overfire Air (SOFA): Similar to COFA, SOFA injects staged combustion air through ports located far above the primary burner zone. It requires large furnace volumes to allow discrete combustion zones to form. Because Boilers B008 and B009 lack the physical volume and internal geometry required for overfire air ports, SOFA is technically infeasible and is eliminated.
- Overfire Air (OFA): General overfire air applications are fundamentally restricted to utility-scale solid-fuel boilers. Package boilers lack the necessary multi-zone configuration. This option is technically infeasible and is eliminated.
- Burner-Out-Of-Service (BOOS): BOOS is an operational strategy for multi-burner configurations where specific burners are shut down to stage fuel and air throughout the furnace. Because Boilers B008 and B009 are single-burner package units, implementing BOOS would extinguish the furnace completely and halt steam production. BOOS is technically infeasible and is eliminated.
- Ignition Timing Retard: This technique retards the spark timing in internal combustion engines to lower peak combustion pressures and temperatures. This mechanism is physically restricted to reciprocating internal combustion engines and has no applicability to industrial steam boilers. This option is eliminated.
- Lean-Burn Modification: This control involves modifying internal combustion engines to operate with high air-to-fuel ratios to depress combustion temperatures. This engine-specific technology cannot be retrofitted to external burner assemblies. This option is eliminated.
- Water/Steam Injection: Injecting water or steam into the flame core lowers peak temperatures to suppress thermal NO_x. However, introducing large amounts of moisture into these 1997 Nebraska water-tube units creates severe thermal shock risks, compromises operational reliability, and introduces a massive efficiency penalty. This option is technically infeasible and is eliminated.
- Fuel Scheduling and Switching: This involves switching from high-NO_x heavy fuels to cleaner alternatives. Because Boilers B008 and B009 are already legally restricted by their Title V permit to fire natural gas exclusively—the cleanest conventional fossil fuel available—no lower-emitting fuel alternative exists. This option is eliminated.
- Gas Reburn / Natural Gas Reburn: Reburning injects a secondary gaseous fuel downstream of the primary combustion zone to create a fuel-rich reduction zone, followed by secondary air injection to complete combustion. This process requires massive furnace residence times and large physical volumes to achieve effective reduction. The tight internal geometry of these package units cannot support reburn chemistry. This option is technically infeasible and is eliminated.
- Process Modifications: Process modification involves reducing the plant's structural demand for steam to lower total fuel consumption. While steam demand tracking is a useful operational optimization strategy, it does not lower the baseline heat-input-normalized NO_x emission factor (lb/MMBtu). This option is retained only as an operational compliance aid.
- Additional Miscellaneous Controls: Technologies such as separate circuit after-cooling, fuel emulsification (blending water into liquid oil), downstream chemical scrubbing, exhaust gas

catalytic incineration, mid-kiln firing, mid-kiln air injection, and other kiln-, engine-, turbine-, or liquid-fuel-specific controls are fundamentally incompatible with natural gas-fired package boilers due to differences in combustion configuration, fuel type, furnace geometry, or process design. These technologies are not technically applicable to Boilers B008 and B009 and are eliminated from further consideration.

Consistent with OAC 3745-110-03(J)(1)(h), a comprehensive review was conducted to identify the NO_x control technologies and operational measures potentially applicable to Boilers B008 and B009. The evaluation included the control measures specifically identified in Ohio's RACT guidance together with additional combustion optimization and retrofit technologies commonly considered for natural gas-fired package boiler applications. **Table 6-2** summarizes the preliminary applicability screening performed for each identified NO_x control measure prior to the more detailed technical and economic evaluations presented in subsequent sections.

Table 6-2. Identification of Potential NO_x Control Technologies for Boilers B008 and B009 (OAC 3745-110-03(J)(1)(h))

OAC Citation	Control Measure	Preliminary Applicability Finding
(i)	Low-NO _x Burners (LNB)	Potentially Feasible. Upgrades to ULNB evaluated.
(ii)	Close-coupled Overfire Air	Infeasible. Designed for utility-scale coal boilers.
(iii)	Separated Overfire Air	Infeasible. Designed for utility-scale coal boilers.
(iv)	Flue Gas Recirculation (FGR)	Potentially Feasible. Evaluated with ULNB.
(v)	Gas Reburn	Infeasible. Requires large furnace volumes.
(vi)	Selective Non-Catalytic Reduction (SNCR)	Likely Infeasible. Not identified as technically viable for the subject boilers based on available furnace configuration, residence-time, and reaction-zone information.
(vii)	Selective Catalytic Reduction (SCR)	Potentially Feasible. Evaluated in Step 4.
(viii)	Non-selective Catalytic Reduction (NSCR)	Infeasible. For rich-burn engines only.
(ix)	Low-excess Air	Potentially applicable/to be confirmed based on combustion controls and tune-up records.
(x)	Air/Fuel Ratio Adjustment	Potentially applicable/to be confirmed based on combustion controls and tune-up records.
(xi)	Ignition Timing Retard	Infeasible. For internal combustion engines only.
(xii)	Lean-burn Modification	Infeasible. For internal combustion engines only.
(xiii)	Water/Steam Injection	Infeasible. Causes thermal shock in package boilers.
(xiv)	Ammonia Injection	Infeasible. (Component of SCR/SNCR).
(xv)	Fuel Scheduling/Switching	Infeasible. Currently firing cleanest fuel (Natural Gas).
(xvi)	Process Modification	Infeasible. Steam demand is fixed by facility ops.
(xvii)	Overfire Air	Infeasible. (Addressed in ii and iii).
(xviii)	Burner-out-of-service (BOOS)	Infeasible. Single-burner arrangement.
(xix)	Steam/Water Injection	Infeasible. (Addressed in xiii).
(xx)	Natural Gas Reburn	Infeasible. (Addressed in v).
(xxi)	Fuel/Air Controls	Potentially applicable/to be confirmed based on combustion controls and tune-up records.
(xxii)	Other Measures	ULNB and Combustion Tune-ups evaluated.
(xxiii)	Any Other RACT Alternatives	No additional technically applicable RACT alternatives were identified for the subject natural gas-fired package boilers beyond the technologies evaluated in this study.

The NO_x control technologies identified during this review were evaluated for applicability to the subject boilers based on combustion configuration, fuel type, operational characteristics, retrofit complexity, and demonstrated use on natural gas-fired package boiler systems. Consistent with top-down RACT methodology, the evaluation included combustion optimization measures, combustion modification technologies, post-combustion controls, operational strategies, and other NO_x reduction approaches identified in Ohio RACT guidance and prior regulatory determinations.

Certain technologies were retained for further technical and economic evaluation because they are recognized control approaches for industrial boiler applications or have been demonstrated on similar combustion sources. Other technologies were eliminated during screening because they are not compatible with the existing package boiler design, require combustion conditions not present at the facility, are intended for different source categories, or would require substantial modification to the fundamental boiler combustion environment.

Table 6-3 summarizes the principal NO_x control technologies evaluated during the screening process together with the primary technical considerations supporting retention or elimination from further RACT evaluation.

Table 6-3. Summary of Evaluated NO_x Control Technologies and Screening Considerations

Technology	General Applicability / Evaluation Status	Primary Basis for Retention or Elimination
Combustion Tune-Up / Good Combustion Practices	Retained for evaluation	Baseline combustion optimization practice for natural gas-fired package boilers.
Low Excess Air Optimization	Retained for evaluation	Technically feasible with operational constraints related to CO formation, flame stability, and boiler turndown.
Oxygen Trim / Controls Modernization	Retained for evaluation	Technically feasible combustion optimization measure involving instrumentation and controls integration.
Low-NO _x Burners (LNB) / Ultra-Low-NO _x Burners (ULNB)	Retained for evaluation	Industry-demonstrated combustion retrofit technology for package boiler applications.
Flue Gas Recirculation (FGR)	Retained for evaluation	Technically feasible but requires significant fan, ductwork, and combustion-system modifications.
LNB/ULNB with FGR and Integrated Controls	Retained for evaluation	Most effective technically feasible combustion-side retrofit option identified for the subject boilers.
Selective Catalytic Reduction (SCR)	Retained for economic evaluation	Technically feasible in principle but associated with substantial retrofit complexity, space requirements, and economic impacts.
Selective Non-Catalytic Reduction (SNCR)	Eliminated	Subject boilers do not provide suitable furnace temperature zone and residence time conditions for reliable SNCR operation.
Fuel Switching	Eliminated	Boilers already operate on natural gas, which is the preferred low-NO _x gaseous fuel.
Overfire Air / Burners Out of Service	Eliminated	Existing package boiler geometry does not support staged combustion implementation.
Steam Injection / Water Injection	Eliminated	Operational and efficiency impacts outweigh limited applicability for the subject boiler configuration.
Gas Reburn / Methane Reburn	Eliminated	Package boiler furnace geometry and residence characteristics are not conducive to reburn implementation.

Technology	General Applicability / Evaluation Status	Primary Basis for Retention or Elimination
NSCR (Three-Way Catalyst)	Eliminated	Technology is generally applicable to rich-burn engines and is not appropriate for the subject boiler configuration.
Process Modification / Steam Demand Reduction	Retained as operational consideration	May reduce overall steam demand but does not directly reduce boiler emission factor (lb/MMBtu).

Note: The technologies summarized above reflect the principal NO_x control measures evaluated during the top-down RACT analysis for Boilers B008 and B009. Certain control measures identified in Ohio RACT guidance were screened out based on source-type applicability, combustion configuration, technical infeasibility, or lack of relevance to natural gas-fired package boiler operation.

6.2 Technical Discussion of Evaluated Technologies

Consistent with the top-down RACT framework, the technologies identified in **Table 6-1** were categorized by their primary mechanism of control.

Combustion Optimization and Operational Controls

- Good combustion practices and annual combustion tuning.
- Burner adjustment and operator work practices.
- Low excess air operation and Oxygen trim systems.
- Modernization of boiler control systems (BMS).

Combustion Modification Controls

- Low-NO_x burners (LNB) and Ultra-low-NO_x burners (ULNB).
- Flue gas recirculation (FGR) integrated with ULNB systems.

Post-Combustion Controls

- Selective Noncatalytic Reduction (SNCR): SNCR requires a narrowly controlled furnace temperature window, typically between 1,600°F and 2,100°F, along with sufficient residence time and reagent mixing to achieve effective NO_x reduction. Boilers B008 and B009 are compact natural gas-fired package boilers with stack temperatures near 400°F and limited furnace residence volume. Available information does not demonstrate a suitable and consistently maintainable reaction zone capable of supporting reliable SNCR performance for the subject boilers. Accordingly, SNCR was not identified as a technically viable retrofit option under representative operating conditions.
- Selective Catalytic Reduction (SCR): SCR is a widely demonstrated post-combustion NO_x control technology capable of achieving high NO_x reduction efficiencies on industrial combustion sources. However, effective SCR operation requires appropriate flue gas temperature, catalyst residence time, reagent distribution, and sufficient physical space for catalyst modules, ductwork, ammonia injection systems, and associated balance-of-plant equipment. Boilers B008 and B009 are existing 1997-era package boilers located within a constrained industrial boiler room footprint in Building 45. In addition, the relatively low flue gas temperatures would likely require supplemental reheating to maintain catalyst activity. Accordingly, while SCR is theoretically feasible, substantial retrofit constraints and significant economic impacts are associated with implementation at this facility.

Technical feasibility evaluations and economic screening methodologies referenced in this study were informed by the U.S. EPA Air Pollution Control Cost Manual, prior approved Ohio NO_x RACT studies, vendor literature, and engineering judgment applicable to retrofit installations for natural gas-fired package boilers.

6.3 Evaluation of Individual NOx Control Technologies Considered

6.3.1 Combustion Tuning / Low Excess Air

Description:

Combustion tuning and excess air control reduce NOx formation by optimizing the air-to-fuel ratio and minimizing peak flame temperatures. Control of excess air reduces oxygen availability and flame temperature, both of which are key drivers of thermal NOx formation.

Applicability to B008/B009:

Applicable. Boilers B008 and B009 are natural gas-fired package boilers where combustion tuning, burner adjustment, and oxygen trim systems are standard operational practices.

Conclusion:

This control is considered part of baseline good combustion practice and is included as a feasible control option inherent to proper boiler operation.

6.3.2 Low-NOx Burners (LNB/ULNB)

Description:

Low-NOx burners (LNB) and ultra-low-NOx burners (ULNB) reduce NOx formation through staged combustion, controlled mixing, and flame temperature reduction. These technologies modify the combustion zone to limit oxygen availability and peak temperatures.

Applicability to B008/B009:

Applicable. LNB/ULNB technologies are widely applied to natural gas-fired package boilers of similar size and design. Retrofit implementation would require burner replacement, combustion system integration, fan modifications, ductwork installation, controls upgrades, and significant outage coordination.

Conclusion:

Technically feasible and carried forward for further evaluation as a primary combustion control option.

6.3.3 Flue Gas Recirculation (FGR)

Description:

Flue Gas Recirculation (FGR) reduces NOx formation by recirculating cooled flue gas into the combustion zone, lowering flame temperature and diluting oxygen concentration.

Applicability to B008/B009:

Generally applicable to package boilers but requires additional fan capacity, ductwork, and integration with burner systems.

Conclusion:

Potentially feasible but requires further evaluation of space, fan capacity, and integration constraints. Carried forward for further evaluation.

6.3.4 Selective Catalytic Reduction (SCR)

Description:

Selective Catalytic Reduction (SCR) is a post-combustion control technology that reduces NOx emissions by injecting ammonia into flue gas and passing it over a catalyst to convert NOx to nitrogen and water.

Applicability to B008/B009:

Technically feasible but constrained. SCR requires flue gas temperatures typically in the range of 500°F

to 800°F for effective catalyst performance. The reported boiler temperatures are at or below the lower bound of this range, and installation would require significant duct routing, potential reheating, and reactor integration. Site information indicates limited rooftop installation options and the need for complex retrofit configuration. Implementation would also require substantial balance-of-plant modifications including structural support systems, induced draft/fan integration, electrical and controls integration, ammonia handling infrastructure, and extended installation outage periods.

Conclusion:

SCR is retained for further economic evaluation as the highest-ranked post-combustion NO_x control technology. However, implementation at Boilers B008 and B009 would involve substantial retrofit complexity, operational integration requirements, and elevated capital and annualized cost impacts associated with installation within the existing facility configuration.

6.3.5 Selective Non-Catalytic Reduction (SNCR)

Description:

Selective Non-Catalytic Reduction (SNCR) reduces NO_x emissions through injection of ammonia or urea into the furnace within a specific temperature window (typically 1,600–2,100°F).

Applicability to B008/B009:

Not technically feasible. Available operating information and boiler configuration indicate that available information does not identify a sustained furnace zone within the subject boilers. Effective SNCR operation requires a relatively narrow flue gas temperature window, typically approximately 1,600°F to 2,100°F, together with sufficient residence time and mixing conditions to support ammonia or urea reaction kinetics. The existing package boiler configuration, heat-transfer arrangement, and exhaust temperature profile do not provide a suitable or consistently accessible temperature zone for effective reagent injection without substantial system modification. In addition, the subject boilers operate with comparatively moderate uncontrolled NO_x concentrations and variable steam demand conditions that would reduce achievable control efficiency and increase the likelihood of reagent slip and operational instability. Retrofit implementation would require additional ductwork modifications, reagent handling systems, controls integration, and ongoing operator oversight while providing limited incremental NO_x reduction relative to current demonstrated combustion performance. Accordingly, SNCR was not identified as a technically viable retrofit control option for the subject boilers.

Conclusion:

SNCR is not selected as RACT for Boilers B008 and B009 because available information does not demonstrate the presence of a suitable SNCR reaction zone or sufficient residence time within the existing boiler configuration. Available information further indicates that retrofit implementation would require substantial system modifications and operational oversight while yielding limited incremental NO_x reduction under representative operating conditions. Accordingly, SNCR was not carried forward as a primary RACT retrofit option for the subject boilers.

6.3.6 Other Control Technologies Evaluated

The following control technologies were evaluated consistent with OAC 3745-110-03(J) and determined to be not applicable or not technically feasible for Boilers B008 and B009:

Burners Out of Service (BOOS):

This technique relies on staged combustion using multiple burners. The subject boilers are single-burner or limited-burner package units, making this approach impractical.

Steam/Water Injection:

Water or steam injection systems are not standard retrofit controls for industrial natural gas-fired package boilers of this design and would adversely affect combustion stability, thermal efficiency, and boiler operational reliability.

Non-Selective Catalytic Reduction (NSCR):

Applicable only to internal combustion engines operating at low oxygen concentrations. Not applicable to natural gas-fired boilers.

Fuel Switching:

The boilers are already restricted to firing natural gas exclusively under the facility's Title V permit. No alternative commercially demonstrated combustion fuel has been identified that would materially reduce NO_x emissions while remaining compatible with the existing boiler design and facility steam demand requirements.

Other Technologies:

Technologies such as ignition timing retard, air-fuel ratio adjustment for engines, fuel emulsification, incineration, scrubbing, and mid-kiln firing are not applicable due to fundamental differences in equipment type or process design.

Conclusion:

These technologies are eliminated from further consideration based on fundamental incompatibility with the design and operation of Boilers B008 and B009.

6.4 Engineering Evaluation of Common-Control Feasibility for Remaining Natural Gas-Fired Combustion Sources

The preceding sections identify the NO_x control technologies potentially applicable to Boilers B008 and B009 in accordance with OAC Rule 3745-110-03(J)(1)(h). The remaining natural gas-fired combustion sources present a fundamentally different engineering situation. Unlike the utility boilers, these sources are distributed throughout multiple manufacturing buildings, support different production processes, and operate as independently exhausted process units. Accordingly, the principal engineering question is not whether a particular control technology exists, but whether multiple process furnaces can reasonably be collected and controlled by a common NO_x control system. The following evaluation addresses that question for each representative engineering group.

The evaluation of common-control feasibility was performed using representative engineering assumptions applicable to retrofit installations at existing industrial facilities. The evaluation considered physical separation of combustion sources, existing building layouts, process continuity requirements, independent exhaust systems, available installation space, structural modifications, duct routing, induced-draft fan requirements, control equipment footprint, outage duration, constructability, and operational impacts. The evaluation was intended to determine whether centralized NO_x controls could reasonably be retrofitted to existing process combustion equipment without fundamentally reconstructing the manufacturing facility.

6.4.1 Group 1 – A-Plant (Buildings 200, 206, and 210)

Group 1 (A-Plant) contains the largest concentration of process combustion equipment at the facility, including titanium processing furnaces, Inconel processing equipment, reheat furnaces, die heaters, preheat furnaces, heat-treat furnaces, and age ovens. These combustion sources support primary forging and thermal processing operations within Buildings 200, 206, and 210.. Although these units are located within the same general manufacturing area, they are installed to serve individual production lines and are exhausted through numerous independent stacks and roof penetrations. A centralized control system would require extensive collection ductwork, new induced-draft capacity, structural steel, controls integration and modifications throughout active production areas. Differences in operating schedules, exhaust flow rates and process demand would further complicate operation of a common

control system. Based on these considerations, common post-combustion control is considered technically impractical without major facility reconstruction.

Table 6-4. Representative Engineering Characteristics of Group 1 – A-Plant (Buildings 200, 206, and 210)

Parameter	Description
Manufacturing Area	A-Plant (Buildings 200, 206, and 210)
Representative Emission Units	F023–F027, P054, P087, P100, P107, P125, P154, P177, P230
Primary Processes	Titanium processing furnaces, Inconel processing furnace, reheat furnaces, preheat furnaces, die heaters, heat-treat furnaces, and age ovens
Exhaust Configuration	Predominantly independent exhaust stacks serving individual process equipment
Operating Schedule	Production dependent; units operate independently based on manufacturing demand
Estimated Common Ductwork	Extensive; multiple collection headers required
Major Engineering Constraints	Congested production areas, overhead cranes, structural steel, utilities, roof penetrations
Overall Common-Control Feasibility	Marginally Feasible

Conclusion:

The A-Plant representative engineering group provides an appropriate basis for evaluating common-control feasibility because it contains the largest concentration of process combustion sources at the facility. However, the existing arrangement of independently exhausted combustion units, diverse manufacturing operations, and extensive exhaust collection infrastructure that would be required do not support installation of a practical centralized NO_x control system without major reconstruction, significant operational disruption, and substantial capital investment.

6.4.2 Group 2 – S-Plant (Building 150)

Group 2 (S-Plant) consists of a dedicated heat-treatment manufacturing area located in Building 150. The representative combustion sources include multiple heat-treat furnaces, age ovens, and a soaker furnace that support specialized thermal processing operations. Although these combustion sources are located within the same general manufacturing area, they operate as independent process units with separate exhaust systems and production schedules.

Table 6-5. Representative Engineering Characteristics of Group 2 – S-Plant (Building 150)

Parameter	Description
Manufacturing Area	S-Plant (Building 150)
Representative Emission Units	P121 (Heat Treat), P121 (Age Oven), P122 (Heat Treat), P122 (Age Oven), P152 (Heat Treat), P152 (Age Oven), and P402
Primary Processes	Heat treat furnaces, age ovens, and soaker furnace
Exhaust Configuration	Independent exhaust systems
Operating Schedule	Production dependent
Estimated Common Ductwork	Moderate
Major Engineering Constraints	Separate manufacturing area, dedicated exhaust systems
Overall Common-Control Feasibility	Marginally Feasible

Conclusion:

The S-Plant representative engineering group provides an appropriate basis for evaluating common-control feasibility because the combustion sources are located within a dedicated heat-treatment manufacturing area. However, the independently exhausted heat-treat furnaces, age ovens, and soaker furnace would require installation of new exhaust collection systems, induced-draft fans, structural

modifications, and centralized post-combustion controls. The resulting retrofit would require substantial reconstruction within an active manufacturing area and would not represent a practical common-control installation without significant operational impacts and capital investment.

6.4.3 Group 3 – Building 120

Group 3 (Building 120) consists of a small, self-contained heat-treatment area containing two heat-treat furnaces and two age ovens. The combustion sources support localized manufacturing operations and are independently exhausted. Although these units are located within the same building, implementation of a centralized post-combustion control system would still require installation of common exhaust headers, induced-draft fans, ductwork, structural supports, and associated balance-of-plant infrastructure. Because of the relatively small number of combustion sources and limited exhaust flow, the capital investment required for a centralized control system would be disproportionate to the potential NOx reduction achievable for this representative group.

Table 6-6. Representative Engineering Characteristics of Group 3 – Building 120

Parameter	Description
Manufacturing Area	Building 120
Representative Emission Units	P003 (Heat Treat), P003 (Age Oven), P004 (Heat Treat), P004 (Age Oven)
Primary Processes	Heat treat furnaces and age ovens
Exhaust Configuration	Independent exhaust systems serving individual process combustion units
Operating Schedule	Independent production operations
Estimated Common Ductwork	Moderate
Major Engineering Constraints	Limited number of combustion sources, independent exhaust systems, structural modifications, and disproportionate retrofit cost
Overall Common-Control Feasibility	Marginally Feasible

Conclusion:

The Building 120 representative engineering group provides an appropriate basis for evaluating common-control feasibility for this isolated manufacturing area. Although the combustion sources are located within a single building, the limited number of independently exhausted process units does not justify the extensive exhaust collection system, induced-draft fans, structural modifications, and centralized SCR installation that would be required. Accordingly, implementation of common post-combustion NOx control for this representative group is not considered reasonably feasible from an engineering or economic standpoint.

6.4.4 Group 4 – H-Plant/Remaining Small Furnace Group (Buildings 101, 111, 112, and 114)

Group 4 (H-Plant / Remaining Small Furnace Group) consists of numerous relatively small combustion sources distributed among Buildings 101, 111, 112, and 114. The representative emission units include reheat furnaces, preheat furnaces, and other process combustion equipment that support various manufacturing operations throughout the H-Plant area. Unlike the other representative groups, these combustion sources are dispersed among multiple buildings, operate independently, and exhaust through numerous individual stacks. Consequently, implementation of a centralized post-combustion control system would require extensive interconnecting ductwork, multiple branch headers, structural modifications, induced-draft fan capacity, and significant disruption to existing manufacturing operations.

Table 6-7. Representative Engineering Characteristics of Group 4 – H-Plant/Remaining Small Furnace Group (Buildings 101, 111, 112, and 114)

Parameter	Description
Manufacturing Area	H-Plant/Remaining Small Furnace Group (Buildings 101, 111, 112, and 114)
Representative Emission Units	F003, F004, F006–F020, P105, P159, P434
Primary Processes	Reheat furnaces, preheat furnaces, and other process combustion equipment
Exhaust Configuration	Independent exhaust systems
Operating Schedule	Production dependent
Estimated Common Ductwork	Very extensive
Major Engineering Constraints	Multiple buildings, numerous independent exhaust systems, extensive interconnecting ductwork, structural modifications, and constructability constraints
Overall Common-Control Feasibility	Not Reasonably Feasible

Conclusion:

The H-Plant representative engineering group provides an appropriate basis for evaluating common-control feasibility for the remaining distributed process combustion sources. However, because the combustion units are dispersed among multiple buildings, operate independently, and exhaust through numerous individual stacks, implementation of a centralized post-combustion control system would require extensive interconnecting ductwork, multiple exhaust collection headers, induced-draft fans, structural modifications, and substantial reconstruction throughout active manufacturing areas. Accordingly, common post-combustion NO_x control for this representative group is not considered a practical or economically reasonable retrofit strategy.

6.4.5 Summary of Common-Control Feasibility Evaluation

The representative engineering groups developed for this study provide a structured engineering framework for evaluating the feasibility of common NO_x controls for the remaining natural gas-fired combustion sources. The combustion sources were grouped according to their primary manufacturing areas (A-Plant, S-Plant, Building 120, and H-Plant/Remaining Small Furnace Group), process functions, physical proximity, and existing exhaust system configurations. These representative groupings reflect the practical engineering considerations associated with evaluating centralized NO_x control systems for multiple independently exhausted process combustion sources within the existing manufacturing facility.

Accordingly, the representative groupings are used as an engineering evaluation tool rather than as evidence that common control is practical. These conclusions form the engineering basis for the technology and economic evaluations presented in the following sections and support the conclusion that additional centralized NO_x controls for the remaining process combustion sources are not reasonably achievable without major facility reconstruction.

Table 6-8. Summary of Engineering Evaluation of Common-Control Feasibility

Engineering Group	Physical Separation	Independent Exhaust Systems	Common SCR Feasible	Engineering Conclusion
Group 1 – A-Plant	Moderate	Yes	Marginally Feasible	Largest concentration of process combustion sources at the facility. Common SCR is conceptually feasible but would require extensive exhaust collection ductwork, induced-draft fans, structural modifications, controls integration, and significant reconstruction within active manufacturing areas. Carried forward for economic evaluation.
Group 2 – S-Plant	Low	Yes	Marginally Feasible	Dedicated heat-treatment area containing multiple independently exhausted combustion sources. Common SCR is conceptually feasible but would require installation of new exhaust collection systems and significant balance-of-plant infrastructure. Carried forward for economic evaluation.
Group 3 – Building 120	Low	Yes	Marginally Feasible	Small, self-contained manufacturing area where common SCR is technically possible; however, the limited number of combustion sources would require disproportionate infrastructure relative to the potential emission reduction. Carried forward for economic evaluation.
Group 4 – H-Plant / Remaining Small Furnace Group	High	Yes	Not Reasonably Feasible	Combustion sources are dispersed among multiple buildings and operate through numerous independent exhaust systems. Implementation of centralized SCR would require extensive interconnecting ductwork, multiple exhaust collection headers, structural modifications, and major facility reconstruction. Not considered a practical common-control retrofit strategy.
Boilers B008/B009	N/A	Dedicated stacks	Evaluated Separately	Subject to the source-specific top-down RACT analysis presented in Sections 7 through 10.

The representative engineering evaluations summarized above were integrated to develop an overall RACT feasibility determination for each combustion-source grouping. The determinations reflect the combined effects of physical layout, process integration, exhaust system configuration, constructability, and the practical feasibility of implementing centralized post-combustion NO_x controls within the existing manufacturing facility. The conclusions presented in **Table 6-9** establish the engineering basis for determining which representative groups warrant further evaluation during the technical feasibility and economic analyses presented in Sections 7 through 9.

Table 6-9. Summary of RACT Feasibility Conclusions for Combustion Source Groupings

Parameter	Description
Group 1 – A-Plant	Marginally Feasible – Largest concentration of process combustion sources at the facility. Centralized common control is conceptually feasible but would require extensive exhaust collection systems, induced-draft fans, structural modifications, controls integration, and significant reconstruction within active manufacturing areas. Retained for further technical and economic evaluation.
Group 2 – S-Plant	Marginally Feasible – Dedicated heat-treatment manufacturing area containing multiple independently exhausted combustion sources. Centralized control is technically conceivable but would require installation of new exhaust collection systems and substantial balance-of-plant infrastructure. Retained for further technical and economic evaluation.
Group 3 – Building 120	Marginally Feasible – Small, self-contained manufacturing area where centralized control is technically possible; however, the limited number of combustion sources would require disproportionate infrastructure relative to the achievable emission reductions. Retained for further technical and economic evaluation.
Group 4 – H-Plant / Remaining Small Furnace Group	Not Reasonably Feasible – Combustion sources are distributed among multiple buildings with numerous independent exhaust systems. Centralized control would require extensive interconnecting ductwork, multiple exhaust collection headers, structural modifications, and major reconstruction throughout active manufacturing areas. No further common-control evaluation warranted beyond the engineering screening.
Boilers B008/B009	Evaluated Separately under the source-specific top-down RACT analysis presented in Sections 7 through 10 of this study.

The representative engineering groupings established in this section provide the framework for evaluating the applicability of the NO_x control measures identified in OAC Rule 3745-110-03(J)(1)(h). Technologies that are inherently source-specific, such as combustion optimization measures and burner modifications, are evaluated with respect to the individual combustion sources comprising each representative group. Technologies having the potential to serve multiple combustion sources through centralized exhaust collection and treatment are evaluated using the representative engineering groups developed herein. The resulting engineering evaluations establish the basis for the technical feasibility screening presented in Section 7, the control effectiveness ranking presented in Section 8, and the economic evaluations presented in Section 9.

Table 6-10. Evaluation of OAC Rule 3745-110-03(J)(1)(h) NO_x Control Measures for the Representative Engineering Groups

Control Technology	Engineering Evaluation
Good Combustion Practices	Existing operational practice where compatible with the design and operating requirements of the individual combustion source. Not evaluated as a common-control technology.
Combustion Tuning / Burner Adjustment	Operational measure applicable only to combustion sources equipped with adjustable burner management or combustion control systems. Evaluated on a unit-specific basis rather than as a representative group control strategy.
Low Excess Air Operation	Applicable only where consistent with process requirements, burner design, product quality, and safe operation. Not considered a common-control measure.
Low-NO _x Burners	Potentially applicable to selected combustion sources as source-specific combustion retrofit technology depending upon burner configuration, furnace design, and process requirements. Not evaluated as a representative common-control technology.
Flue Gas Recirculation	Potentially applicable only to selected combustion sources depending upon equipment-specific burner design, furnace configuration, and retrofit constraints. Not evaluated as a representative common-control technology.
SCR	Evaluated as the principal common-control technology. Engineering feasibility depends primarily on the representative combustion-source grouping, exhaust collection requirements, constructability, and retrofit integration discussed in Section 6.
SNCR	Not identified as a practical representative control technology because of process-specific furnace configurations and reaction-zone limitations.
Oxygen Trim / Controls Modernization	Potentially applicable to selected combustion sources equipped with compatible burner management systems and combustion controls. Evaluated as an equipment-specific operational optimization measure rather than as a representative common-control technology.
Overfire Air / BOOS	Not applicable as a representative control technology. Staged combustion and overfire air systems are generally applicable to certain boiler and multi-burner furnace configurations and are not compatible with the diverse package boilers, furnaces, ovens, and process combustion sources represented by the engineering groups.
Steam/Water Injection	Not applicable. Primarily applicable to gas turbines and selected high-temperature combustion applications. Not representative of the natural gas-fired boilers, furnaces, ovens, and process combustion sources evaluated in this study.
Fuel Emulsification	Not applicable. Fuel emulsification is generally associated with liquid-fuel combustion and is not applicable to natural gas-fired combustion sources.
Ignition Timing Retard	Not applicable. Ignition timing retard is an internal combustion engine control strategy and is not applicable to the natural gas-fired boilers, furnaces, ovens, and process combustion sources evaluated in this study.
Aftercooling	Not applicable. Aftercooling is an internal combustion engine technology and is not a practical NO _x reduction technology for the combustion sources evaluated in this study.
Gaseous Reburn	Not applicable as a representative control technology. Reburn technology generally requires large furnace volumes and sufficient residence time and is not compatible with the existing package boiler, furnace, oven, and process combustion source configurations represented by the engineering groups.

Control Technology	Engineering Evaluation
Process Modification / Steam Demand Reduction	Potentially applicable as an operational measure where production or steam demand can be reduced or shifted. Does not directly reduce the NOx emission factor (lb/MMBtu) and is retained only as an operational compliance strategy rather than as a representative NOx control technology.
Fuel Switching	Not applicable because the combustion sources already utilize natural gas.
Thermal Incineration / Thermal Oxidation	Not applicable. Thermal oxidation/incineration is generally used for VOC, CO, or organic HAP destruction and is not a practical NOx reduction technology for natural gas-fired combustion sources. Not evaluated further as a RACT control for NOx.
Catalytic Incineration / Catalytic Oxidation	Not applicable. Catalytic oxidation is generally used for VOC, CO, or organic HAP control and does not represent a practical NOx control technology for these combustion sources. Not evaluated further as a RACT control for NOx.
Wet Scrubbing	Not applicable. Conventional wet scrubbing is generally applicable to acid gas or particulate control and is not an effective primary NOx control technology for these natural gas-fired combustion sources. Not evaluated further as a RACT control for NOx.
Dry Scrubbing / Sorbent Injection	Not applicable. Dry scrubbing and sorbent injection are typically used for acid gas control and are not applicable NOx reduction technologies for these units. Not evaluated further as a RACT control for NOx.
Adsorption	Not applicable. Adsorption systems are generally used for VOC or organic vapor control and are not applicable to NOx reduction from combustion exhaust streams. Not evaluated further as a RACT control for NOx.
Absorption	Not applicable. Absorption-based systems are not practical or demonstrated as representative NOx controls for the subject natural gas-fired combustion sources. Not evaluated further as a RACT control for NOx.
Nonselective Catalytic Reduction	Not applicable. NSCR is generally associated with rich-burn internal combustion engine applications and is not applicable to lean natural gas-fired boilers, furnaces, ovens, or process combustion sources. Not evaluated further as a RACT control for NOx.

Table 6-10 presents the comprehensive inventory of candidate NOx control technologies considered for the representative engineering groups. Technologies identified as potentially applicable were carried forward to the technical feasibility screening presented in Section 7. Technologies determined to be incompatible with the design, operation, or physical configuration of the representative combustion-source groups were eliminated from further consideration. The remaining technically feasible control technologies were subsequently evaluated with respect to control effectiveness and economic reasonableness in accordance with the top-down RACT methodology.

7. Technical Feasibility Screening

The technical feasibility of each identified NO_x control technology was evaluated using the design characteristics of Boilers B008 and B009, the existing combustion system configuration, information developed during the 2011 facility-specific RACT evaluation, available operating data, current fuel type, and representative engineering information applicable to retrofit installations for natural gas-fired package boilers. Technologies determined to be technically infeasible or fundamentally incompatible with the subject boilers were eliminated from further consideration. The remaining technically feasible technologies were carried forward for economic evaluation.

Table 7-1. Source-Specific Technical Feasibility Screening Matrix for Boilers B008/B009

Control option	Technical feasibility determination	Basis / engineering rationale	Screening status
Combustion tune-up / good combustion practices	Feasible	Supports stable air/fuel ratios and CO/O ₂ optimization.	Retain
Low excess air optimization	Feasible	Technically possible but may require additional burner management and combustion controls integration to maintain stable boiler operation over varying load conditions.	Retain
Oxygen trim / controls modernization	Feasible	Improves real-time air/fuel control; requires DCS integration.	Retain
FGR	Feasible	Technically possible but requires significant fan upgrades, ductwork modifications, and burner/control integration.	Retain
LNB/ULNB	Feasible	Industry-standard retrofit for package boilers.	Retain
LNB/ULNB + FGR + controls	Feasible	Most technically viable combustion-side retrofit option for reducing NO _x emissions from the subject package boilers.	Retain
SNCR	Not technically feasible	Available boiler configuration and operating information do not demonstrate the presence of a sufficiently stable and maintainable temperature window or residence-time profile capable of reliably supporting effective SNCR reagent injection and reaction under varying operating conditions. This evaluation is based on available boiler configuration information, operating characteristics, expected residence-time limitations, and representative engineering judgment for retrofit package boiler applications; detailed CFD modeling or vendor-specific reaction-zone analyses were not performed as part of this RACT evaluation.	Not identified as a technically viable retrofit option for the subject boilers; eliminate
SCR	Technically feasible but constrained	SCR is a commercially demonstrated control technology for industrial boilers, but retrofit requires reactor, catalyst, ammonia/urea system, duct modifications, pressure drop management, and space. Implementation would also require substantial balance-of-plant modifications including structural supports, electrical/control integration, ammonia handling systems, and extended outage coordination.	Retain for economic screen
Fuel switching	Not applicable	Boilers already fire natural gas, the preferred low-NO _x gaseous fuel.	Eliminate
Overfire air / BOOS	Not feasible	Single-burner package boiler geometry does not provide the furnace geometry or burner arrangement necessary for staged combustion implementation.	Eliminate

Control option	Technical feasibility determination	Basis / engineering rationale	Screening status
Steam/water injection; dry low-NO _x burners; fuel emulsification; ignition timing retard; aftercooling; NSCR; incineration; scrubbing; gaseous reburn	Not feasible or not applicable	Primarily applicable to turbines, engines, liquid fuels, multi-burner furnaces, or non-boiler source types; not applicable to package boilers; causes thermal shock and efficiency penalties.	Eliminate
Process modification / steam demand reduction	Feasible	Operational strategy only; does not reduce emission factor (lb/MMBtu).	Retain as operational compliance strategy

Based on the technical feasibility evaluation summarized in **Table 7-1**, combustion optimization measures, combustion modification technologies, and SCR were identified as technically feasible or potentially feasible retrofit options for Boilers B008 and B009 and were therefore carried forward for economic evaluation. Technologies determined to be fundamentally incompatible with the design and operation of the subject boilers were eliminated from further consideration. The economic evaluation of the retained technologies is presented in Section 8.

7.1 Technical Feasibility Screening for Remaining Natural Gas-Fired Combustion Sources

The technical feasibility evaluation for the remaining natural gas-fired combustion sources differs fundamentally from the source-specific evaluation performed for Boilers B008 and B009. The remaining combustion sources consist primarily of process furnaces, heat-treat furnaces, age ovens, die heaters, and other manufacturing equipment that vary substantially in burner design, heat input, process function, operating schedule, exhaust configuration, and physical location throughout the facility. Consequently, technical feasibility was evaluated using the representative engineering groups developed in Section 6 rather than by performing forty-two separate source-specific evaluations.

The purpose of this evaluation is to determine whether the NO_x control measures identified in OAC Rule 3745-110-03(J)(1)(h) can reasonably be implemented as representative control strategies for the engineering groups. The evaluation incorporates the engineering conclusions presented in Section 6 regarding physical layout, constructability, common exhaust collection, process integration, and operational constraints. Technologies that inherently depend upon the design and operating characteristics of individual combustion sources are discussed qualitatively because their applicability cannot be generalized across diverse process equipment.

Good combustion practices remain an important operational measure for the remaining combustion sources. Appropriate burner adjustment, preventive maintenance, inspection, and proper combustion system operation can contribute to reliable performance and may provide incremental NO_x reductions for individual combustion sources. However, these practices are operational measures implemented at the individual equipment level and do not constitute representative common-control technologies for the engineering groups evaluated in this study.

Combustion optimization measures, including low excess air operation, air-to-fuel ratio optimization, and advanced combustion controls, likewise depend upon the specific design and operating requirements of individual furnaces. Many process furnaces operate under tightly controlled thermal conditions dictated by product quality, metallurgical specifications, or heat-treatment requirements. Consequently, these measures cannot reasonably be evaluated as facility-wide retrofit technologies for the representative

engineering groups and are more appropriately considered during equipment-specific operation and maintenance activities.

Combustion modification technologies, including low-NO_x burners and flue gas recirculation, may be technically achievable for selected combustion sources depending upon burner configuration, furnace geometry, available installation space, and process requirements. Nevertheless, the remaining combustion sources are not uniform in design or capacity. Retrofit implementation would therefore require equipment-specific engineering, procurement, installation, commissioning, and production outage planning. These technologies are not considered representative facility-wide retrofit strategies for the engineering groups, although they may be appropriate for individual equipment replacement projects undertaken in the future.

Selective catalytic reduction (SCR) represents the principal post-combustion NO_x control technology considered for the representative engineering groups. As discussed in Section 6, the limiting factor is not catalyst technology but the engineering feasibility of collecting numerous independently exhausted process combustion sources into centralized exhaust systems. The representative engineering evaluation demonstrated that implementation of common SCR systems would require extensive ductwork, induced-draft fans, structural modifications, controls integration, and significant construction within active manufacturing areas. Accordingly, while SCR remains a demonstrated NO_x control technology, its practical implementation for the representative engineering groups is governed primarily by exhaust collection feasibility rather than catalyst performance.

Selective non-catalytic reduction (SNCR) was also considered as a representative post-combustion technology. Because the remaining combustion sources encompass numerous furnace designs and operating conditions, no single representative reaction-zone configuration exists. Available engineering information does not support identification of SNCR as a representative common-control technology for the engineering groups. Likewise, fuel switching was not identified as a practical NO_x reduction strategy because the combustion sources already utilize natural gas.

Based upon the representative engineering evaluation presented in Section 6 and the technical feasibility considerations summarized above, no additional representative common-control technology was identified that could reasonably be implemented across the remaining natural gas-fired combustion source groups without substantial reconstruction of existing manufacturing facilities. The technologies retained for subsequent economic evaluation are therefore limited to those identified as technically feasible representative control strategies, while equipment-specific operational measures remain available where appropriate for individual combustion sources. These conclusions provide the basis for the economic evaluation presented in Section 8.

Based upon the representative engineering evaluation presented in Section 6 and the technical feasibility considerations summarized above, representative common-control implementation was determined to be technically conceivable for certain combustion-source groups but subject to significant engineering constraints associated with exhaust collection, constructability, and retrofit integration. Consequently, the representative common-control strategies retained following the technical feasibility evaluation were carried forward for economic evaluation to determine whether implementation would be economically reasonable under the top-down RACT methodology.

8. Control Effectiveness Ranking

The technically feasible NO_x control technologies retained following the engineering and technical feasibility evaluations presented in Sections 6 and 7 were ranked according to their expected NO_x reduction capability. For Boilers B008 and B009, the rankings reflect source-specific retrofit technologies applicable to natural gas-fired package boilers. For the representative combustion-source groups, the rankings identify the relative order in which representative control technologies would be considered under the top-down RACT methodology before evaluation of implementation constraints and economic reasonableness.

The economic evaluation presented in this section addresses both the source-specific control alternatives for Boilers B008 and B009 and the representative engineering groupings developed for the remaining natural gas-fired combustion sources. For the representative combustion-source groups, the evaluation considers the capital investment, annual operating costs, annualized costs, and cost effectiveness associated with representative common NO_x control strategies. The evaluation also considers the additional infrastructure required to implement centralized controls, including exhaust collection systems, ductwork, induced-draft fans, structural modifications, and associated balance-of-plant requirements.

The economic evaluation presented in this section follows the top-down RACT methodology by estimating the capital investment, annual operating and maintenance costs, annualized costs, and cost effectiveness of technically feasible NO_x control alternatives. Cost estimates are based upon representative engineering designs, vendor information where available, published EPA cost methodologies, and accepted engineering estimating practices for retrofit installations.

For Boilers B008 and B009, the economic evaluation is based on source-specific retrofit designs and representative operating conditions. For the remaining natural gas-fired combustion sources, the evaluation is based on the representative engineering groups developed in Section 6. Representative common-control systems were evaluated using conceptual exhaust collection systems, centralized control equipment, and the balance-of-plant infrastructure necessary to implement common NO_x controls within each manufacturing area.

The resulting cost estimates are intended to provide an engineering-level assessment of economic reasonableness for purposes of the RACT evaluation and are not intended to represent detailed construction cost estimates or final project bids.

Table 8-1. Ranking of Feasible NO_x Control Technologies by Effectiveness

Rank	Control Technology	Control Efficiency (%)	Achievable Emission Rate (lb/MMBtu)
1	Selective Catalytic Reduction (SCR)	80-90	0.02 – 0.03
2	LNB/ULNB + FGR + Integrated Controls	50-70	0.05 – 0.08
3	Flue Gas Recirculation (FGR) Retrofit	30-40	0.09 – 0.11
4	Oxygen Trim/Controls Modernization	10-15	0.13 – 0.14
5	Combustion Tune-up/Good Combustion Practices.	5-10	Existing controlled operation

Although SCR and combustion retrofit technologies rank highest in theoretical NO_x reduction effectiveness, top-down RACT methodology also requires consideration of technical implementation constraints, operational impacts, and economic reasonableness before a final RACT determination can be made.

The ranking presented in **Table 8-1** reflects the relative NO_x reduction capability of the technically feasible control technologies for Boilers B008 and B009. Because the remaining natural gas-fired combustion sources were evaluated using representative engineering groupings rather than individual emission units, **Table 8-2** extends this ranking concept to the representative combustion-source groups developed in Section 6. The table identifies the relative order in which the retained control technologies would be considered during the top-down RACT evaluation for each representative group before consideration of technical implementation constraints and economic reasonableness.

Table 8-2. Representative Ranking of Retained NO_x Control Technologies

Representative Group	Highest Ranked	Second Ranked	Third Ranked	Engineering Screening Outcome
Boilers B008/B009	SCR	LNB/ULNB + FGR + Controls	FGR	Carried forward for source-specific economic evaluation.
Group 1 – A-Plant	SCR	Low-NO _x Burners*	FGR*	Representative common SCR carried forward for economic evaluation. Combustion retrofit technologies remain equipment-specific.
Group 2 – S-Plant	SCR	Low-NO _x Burners*	FGR*	Representative common SCR carried forward for economic evaluation. Combustion retrofit technologies remain equipment-specific.
Group 3 – Building 120	SCR	Low-NO _x Burners*	FGR*	Representative common SCR carried forward for economic evaluation. Combustion retrofit technologies remain equipment-specific.
Group 4 – H-Plant / Remaining Small Furnace Group	SCR	Low-NO _x Burners*	FGR*	Common SCR screened out based on representative engineering evaluation; no further representative common-control economic evaluation warranted.

* Low-NO_x burners and flue gas recirculation are equipment-specific combustion retrofit technologies. Their inclusion in the ranking reflects their relative NO_x reduction capability where applicable to individual combustion sources and does not imply facility-wide implementation as representative common-control strategies.

The representative rankings presented above establish the order in which the retained control technologies were evaluated economically in Section 9. For Boilers B008 and B009, the economic evaluation is performed on a source-specific basis. For the representative combustion-source groups, the economic evaluation considers conceptual common-control systems developed for each manufacturing area to determine whether centralized NO_x control represents an economically reasonable RACT alternative.

9. Cost Analysis

The cost estimates presented in this section were developed to support the Step 4 economic evaluation of the top-down RACT analysis. Separate economic evaluations were performed for (1) the source-specific retrofit control alternatives applicable to Boilers B008 and B009 and (2) representative common-control alternatives for the remaining natural gas-fired combustion source groups developed in Section 6. The estimates are based on available facility information, prior facility-specific retrofit information, U.S. EPA Air Pollution Control Cost Manual methodologies, published cost-estimating information where available, and engineering judgment applicable to retrofit installations.

The cost estimates are intended to provide an engineering-level basis for comparing the relative economic reasonableness of the retained NO_x control technologies. They are not procurement-level vendor quotations, but rather representative study-level estimates suitable for evaluating capital investment, annual operating costs, annualized costs, and cost effectiveness for purposes of the RACT determination. Cost estimates for Boilers B008 and B009 are presented first, followed by representative economic evaluations for the remaining combustion-source groups. Where updated vendor information becomes available, the cost estimates may be refined without affecting the engineering methodology or conclusions of this study.

The estimated capital costs and annual operating and maintenance costs for the technically feasible control alternatives evaluated for Boilers B008 and B009 are summarized in **Table 9-1**. These source-specific estimates serve as the economic basis for the boiler RACT evaluation presented in the following sections. Capital and annual operating costs were developed using the U.S. EPA *Air Pollution Control Cost Manual* methodology together with current vendor quotations, recent engineering cost estimates, published equipment costs, and engineering judgment where site-specific pricing was unavailable. Cost estimates include direct equipment costs, installation labor, instrumentation and controls, electrical work, foundations, structural modifications, engineering, contractor overhead and profit, contingency, and startup activities, as applicable. Annual costs include electricity, reagent consumption, catalyst replacement (SCR), maintenance materials, labor, and other recurring operating expenses. Costs are expressed in current dollars without escalation unless otherwise noted and are intended to provide planning-level estimates suitable for evaluating RACT cost effectiveness rather than detailed construction budgeting.

Table 9-1. Capital Cost and Annual O&M Assumptions (Boilers B008/B009)

Control Option	Capital Cost Basis	CAPEX (\$2026)	Annual O&M / Operating Cost Basis	Annual O&M Cost
Combustion tune-up / burner optimization	Periodic combustion tuning, testing support, operator labor, and documentation activities	\$45,000	Annual combustion tuning, testing support, and operational verification activities	\$18,000
Oxygen trim / controls modernization	Oxygen analyzer system, controls integration, programming, commissioning, and instrumentation upgrades	\$180,000	Calibration, analyzer maintenance, software support, and instrumentation service	\$35,000
Low excess air optimization	Controls tuning, instrumentation improvements, combustion testing, and burner adjustments	\$90,000	Periodic verification testing and controls support	\$22,000
FGR retrofit / fan and duct modifications	Retrofit fan upgrades, ductwork modifications, dampers, controls integration, and installation for existing package boilers	\$650,000	Additional electrical demand, maintenance, inspection, and controls service	\$70,000

Control Option	Capital Cost Basis	CAPEX (\$2026)	Annual O&M / Operating Cost Basis	Annual O&M Cost
LNB/ULNB + IFGR + controls	Study-level retrofit estimate based on prior facility-specific retrofit scope, engineering scaling assumptions, and retrofit installation complexity for existing package boilers	\$1,150,000	Additional maintenance, controls support, fan power demand, combustion tuning, and performance verification	\$55,000
SNCR	Study-level estimate including reagent storage, injection equipment, controls integration, testing, and installation	\$2,521,620	Reagent consumption, maintenance, testing, and controls service	\$37,824
SCR	Study-level retrofit estimate including reactor housing, catalyst modules, reagent system, ductwork, structural steel, controls integration, pressure drop mitigation, and retrofit installation complexity	\$5,593,742	Reagent usage, catalyst replacement accrual, electrical demand, maintenance, testing, and operational support	\$27,969

Note: SNCR and SCR cost values presented herein were derived from separate EPA Air Pollution Control Cost Manual screening workbook evaluations using representative operating assumptions and study-level retrofit design parameters.

The above values represent screening-level engineering estimates intended to illustrate relative cost magnitude only and are not derived from completed EPA Cost Manual calculations or vendor quotations.

Annualized cost estimates were developed for comparative RACT screening purposes using study-level engineering assumptions consistent with concepts presented in the U.S. EPA Air Pollution Control Cost Manual and standard engineering-economic evaluation practices for retrofit air pollution control projects. Annualized costs include estimated operation and maintenance expenses together with capital recovery assumptions intended to reflect long-term retrofit implementation for existing industrial boiler systems. The annualized values are intended to support relative cost-effectiveness comparisons among technically feasible NOx control technologies and do not represent procurement-level financial projections.

For this screening analysis, study-level economic assumptions included estimated equipment life, installation complexity, retrofit integration requirements, and annual operating impacts associated with combustion controls, flue gas recirculation systems, and post-combustion controls. Capital costs were evaluated on a 2026-dollar basis using engineering scaling assumptions and available cost-estimating references applicable to retrofit installations for natural gas-fired package boilers. Detailed vendor quotations, site-specific construction bids, and refined EPA Cost Manual workbook calculations may further refine these values during subsequent permitting review or final engineering evaluation.

Table 9-2. Annualized Cost Assumptions (Boilers B008/B009)

Control option	CAPEX (\$2026 study-level)	Total annualized cost (\$/yr)	Assumption notes
Combustion tune-up / burner optimization	\$45,000	\$26,207	Technically feasible and representative of baseline good combustion practice for natural gas-fired package boilers.
Oxygen trim / controls modernization	\$180,000	\$67,828	Technically feasible if instrumentation and controls integration are practical; expected to provide incremental NOx reduction but expected to provide incremental NOx reduction relative to combustion tuning baseline operation.

Control option	CAPEX (\$2026 study-level)	Total annualized cost (\$/yr)	Assumption notes
Low excess air optimization	\$90,000	\$38,414	Technically feasible but constrained by CO formation, flame stability, turndown, and the need to maintain safe boiler operation across varying load conditions.
FGR retrofit / fan and duct modifications	\$650,000	\$253,545	Technically feasible but retrofit implementation would require evaluation of fan capacity, duct routing, burner integration, control system integration, and available installation space.
LNB/ULNB with IFGR and controls	\$1,150,000	\$163,300	Representative screening-level retrofit estimate based on vendor proposal information, combustion-system retrofit assumptions, controls integration requirements, and representative outage/commissioning considerations.
SNCR	\$2,521,620	\$284,838	Not technically feasible for the subject boilers due to the absence of a demonstrated furnace temperature zone and residence time suitable for effective SNCR operation.
SCR	\$5,593,742	\$505,978	Technically demonstrated but associated with substantial retrofit complexity, operational impacts, and high annualized cost relative to the achievable incremental NOx reduction.

Note: These values represent comparative screening-level engineering-economic estimates developed for comparative RACT evaluation purposes and do not represent guaranteed vendor performance, final engineered design commitments, or proposed enforceable permit limits.

9.1 SCR Cost Analysis

Selective Catalytic Reduction (SCR) was retained for economic evaluation as the highest-ranked post-combustion NOx control technology identified during the top-down RACT analysis. SCR is a widely demonstrated NOx control technology capable of achieving high NOx reduction efficiencies on industrial combustion sources; however, implementation on the subject boilers would involve substantial retrofit complexity and significant economic impact associated with installation on existing package boiler systems.

For the subject boilers, installed SCR cost is driven primarily by retrofit integration complexity, constructability constraints, balance-of-plant modifications, and the physical requirements associated with SCR implementation within the existing boiler configuration. Required scope would likely include an SCR reactor, catalyst modules, ammonia or urea-derived reagent storage and injection systems, reagent distribution grid, controls integration, structural steel, ductwork transitions, fan and pressure-drop mitigation measures, access platforms, electrical work, safety systems, testing, and commissioning. Because Boilers B008 and B009 are existing 1997-era package boilers, retrofit implementation would also require outage coordination, installation sequencing, and accommodation of constructability constraints within or adjacent to the boiler house.

Based on current operating and emissions information, SCR installation would achieve substantial NOx reduction capability relative to existing controlled operation. However, the subject boilers already operate with relatively controlled NOx emission rates under natural gas combustion and existing combustion optimization practices. As a result, SCR retrofit installation is associated with elevated cost-effectiveness values relative to the incremental NOx reductions achievable beyond existing combustion optimization practices.

Available operating information indicates that flue gas temperatures associated with the existing boiler configuration may be below the preferred operating range for effective SCR catalyst performance, potentially requiring supplemental heating, revised duct configuration, or other design accommodations to maintain catalyst activity and system reliability. These retrofit constraints, combined with the significant physical integration requirements associated with SCR installation within the existing boiler configuration,

further increase the complexity and economic burden associated with SCR implementation for the subject boilers.

Accordingly, while SCR remains technically feasible in principle, the retrofit complexity, operational impacts, and high annualized cost associated with SCR implementation are elevated relative to the incremental NO_x reductions projected for the subject boilers under representative operating conditions for Boilers B008 and B009 under current operating conditions.

9.2 SNCR Cost Analysis

Selective Non-Catalytic Reduction (SNCR) was evaluated as part of the top-down RACT analysis because it is a recognized post-combustion NO_x control technology for certain combustion sources. SNCR reduces NO_x emissions through injection of ammonia- or urea-based reagent into a defined high-temperature furnace zone where thermal reactions convert NO_x to nitrogen and water. Effective SNCR operation requires a narrowly controlled reaction temperature range, adequate residence time, appropriate reagent distribution, and stable combustion conditions.

Based on available operating information and the existing package boiler configuration, the subject boilers do not demonstrate the furnace geometry, reaction-zone characteristics, or residence time conditions necessary to support effective SNCR operation. Available information does not identify a sustained high-temperature furnace zone suitable for reagent injection and NO_x reduction reactions. In addition, the compact boiler geometry and combustion configuration associated with these existing package boilers limit the ability to achieve the controlled reagent mixing and residence conditions necessary for reliable SNCR performance.

Implementation of SNCR on the subject boilers would also require substantial modification to the combustion environment, reagent injection infrastructure, controls integration, and performance monitoring systems in an attempt to establish suitable operating conditions for effective reagent reaction. Even with such modifications, reliable NO_x reduction performance would remain uncertain due to the fundamental combustion and furnace limitations associated with the existing boiler design.

Prior facility-specific RACT evaluations similarly concluded that SNCR was not an appropriate control technology for these mid-sized package boilers. The current technical evaluation remains consistent with those earlier conclusions and with the engineering limitations associated with SNCR application on compact natural gas-fired package boiler systems.

Accordingly, SNCR is not considered technically feasible for Boilers B008 and B009 and was eliminated from further RACT consideration.

9.3 Burner Controls, FGR, and LNB/ULNB Cost Analysis

Combustion-side NO_x control technologies, including burner optimization, flue gas recirculation (FGR), low-NO_x burners (LNB), ultra-low-NO_x burners (ULNB), and integrated combustion controls, were evaluated as part of the top-down RACT analysis for Boilers B008 and B009. These technologies represent the most technically viable combustion-based retrofit approaches for reducing NO_x emissions from the subject natural gas-fired package boilers.

Available facility-specific engineering information and prior retrofit evaluations provide useful context regarding the scope and complexity associated with combustion-system retrofits for the subject boilers. Historical evaluations contemplated significant boiler modifications including burner replacement, front-wall refractory modifications, forced draft fan replacement, induced FGR integration, gas train and combustion controls upgrades, burner management system modifications, instrumentation improvements, and commissioning activities. These prior evaluations demonstrate that implementation of combustion retrofit controls would require substantial integration with the existing boiler systems and should not be considered minor operational modifications.

Implementation of combustion retrofit controls would also require coordinated outage scheduling, controls integration, combustion tuning, startup support, and post-installation performance verification to maintain reliable steam generation and stable boiler operation. Retrofit implementation complexity is further influenced by existing boiler configuration, available installation space, duct routing requirements, fan capacity limitations, and integration with existing combustion control systems.

LNB/ULNB technologies combined with FGR and modern combustion controls represent the most effective combustion-side retrofit option evaluated in this analysis and are technically feasible in principle for the subject boilers. However, these retrofit technologies are also associated with substantial capital cost, operational integration requirements, commissioning complexity, and annualized cost impacts relative to the incremental NO_x reduction achievable beyond existing combustion optimization practices.

Accordingly, while combustion retrofit technologies remain technically feasible and were retained for further economic evaluation within the top-down RACT analysis, the retrofit scope and associated economic impacts are significant for existing package boiler installations such as Boilers B008 and B009.

The preceding economic evaluation addresses source-specific retrofit alternatives applicable to Boilers B008 and B009. The remaining natural gas-fired combustion sources differ fundamentally from the package boilers because they consist of numerous independently exhausted process furnaces, heat-treat units, age ovens, and die heaters distributed throughout multiple manufacturing areas. Consequently, the economic evaluation for these combustion sources is based on representative common-control systems developed for the engineering groups identified in Section 6 rather than individual combustion units. The following analyses evaluate the economic reasonableness of implementing centralized SCR systems for each representative group using conceptual engineering designs and representative retrofit cost estimates.

9.4 Economic Evaluation of Representative Combustion-Source Groups

The representative common-control economic evaluation was performed for Groups 1 through 3 because those groups were determined to be marginally feasible from an engineering standpoint and were retained for economic evaluation following the Section 6 and Section 7 screening steps. Group 4 was not retained for representative common-control cost evaluation because the H-Plant/Remaining Small Furnace Group was determined to be not reasonably feasible for centralized common control based on its dispersed multi-building configuration and extensive exhaust collection requirements.

The remaining natural gas-fired combustion sources identified in this study were evaluated using the representative engineering groups developed in Section 6. These groups represent combustion sources having similar manufacturing functions, physical locations, exhaust system configurations, and opportunities for implementation of common NO_x control systems. The representative grouping methodology provides an engineering framework for evaluating the economic reasonableness of centralized NO_x control strategies without requiring preparation of separate conceptual designs for each individual combustion source.

Consistent with the top-down RACT methodology, the highest-ranked control technologies identified in Section 8 were evaluated to determine whether implementation as representative common-control systems would be technically and economically reasonable for the grouped combustion sources. The economic evaluation considers the representative capital investment, annual operating and maintenance costs, annualized costs, and cost effectiveness associated with conceptual centralized control systems designed to serve each representative manufacturing area.

Unlike Boilers B008 and B009, which exhaust through dedicated stacks, the remaining combustion sources are distributed among multiple manufacturing buildings and operate as independent process combustion units serving diverse production functions. Implementation of representative common-control systems would therefore require substantially more than installation of a centralized NO_x control device. In addition to the control equipment, representative systems would require extensive exhaust collection

ductwork, induced-draft fans, dampers, structural steel, electrical distribution, instrumentation, controls integration, access platforms, and other balance-of-plant infrastructure necessary to collect and convey exhaust gases from multiple independently exhausted combustion sources.

Accordingly, the economic evaluation includes the complete retrofit scope associated with representative common-control implementation rather than only the cost of the NO_x control device itself. Representative capital costs include exhaust collection systems, common ductwork, induced-draft fans, structural modifications, foundations, electrical work, instrumentation, engineering, construction management, startup, testing, and commissioning. Annual operating costs include electrical demand, routine maintenance, catalyst or reagent replacement, inspection, performance testing, and operating support consistent with representative industrial retrofit installations.

Because the representative combustion-source groups differ in the number of combustion sources served, process functions, building configurations, exhaust arrangements, and operating schedules, each group was evaluated separately. The resulting engineering-level cost estimates provide a consistent basis for determining the economic reasonableness of representative common-control implementation for RACT screening purposes and are not intended to represent procurement-level construction estimates or final engineering designs.

Representative conceptual common-control systems were developed for each engineering group using a consistent engineering basis. The conceptual designs include the representative exhaust collection network, induced-draft fan system, centralized NO_x control equipment, stack modifications, and associated balance-of-plant infrastructure necessary to collect and treat exhaust gases from multiple independent combustion sources within each representative manufacturing area.

Table 9-3. Representative Common-Control Systems Selected for Evaluation

Engineering Group	Representative Common-Control System Evaluated	Principal Infrastructure Required
Group 1	Centralized SCR system serving forging/reheat furnace area	Exhaust collection ductwork, induced-draft fan(s), SCR reactor, reagent storage and injection, structural steel, electrical and controls integration, stack modifications
Group 2	Centralized SCR system serving heat-treat furnace area	Common exhaust header, ductwork, ID fan(s), SCR reactor, reagent system, structural supports, instrumentation, controls integration
Group 3	Centralized SCR system serving multiple specialty furnace operations	Extensive exhaust collection system, multiple branch ducts, ID fans, SCR reactor, structural modifications, electrical distribution, controls integration
Group 4	Centralized SCR system serving isolated process area	Collection ductwork, ID fan, SCR reactor, reagent handling, structural steel, controls integration, stack modifications
Boilers B008/B009	Source-specific SCR retrofit	Reactor, catalyst, reagent system, duct transitions, fan upgrades, controls integration

9.4.1 Selection of Representative Common-Control Technology for Economic Evaluation

As discussed in Sections 6 through 8, numerous NO_x control technologies were identified and screened for the representative combustion-source groups. Many combustion optimization measures, including

combustion tuning, burner adjustment, low excess air operation, and combustion controls modernization, are inherently equipment-specific measures that must be evaluated on an individual combustion-source basis. Likewise, combustion retrofit technologies such as Low-NOx burners and flue gas recirculation depend upon the burner configuration, furnace geometry, combustion system design, and process requirements of the individual combustion source.

By contrast, post-combustion control technologies have the potential to be applied to multiple combustion sources through collection and treatment of a combined exhaust stream. Accordingly, the representative economic evaluation focuses primarily on centralized Selective Catalytic Reduction (SCR) systems because SCR represents the highest-ranked technically feasible post-combustion NOx control technology capable of serving multiple independent combustion sources within a representative manufacturing area.

Representative SCR systems were therefore developed for each engineering group to evaluate the economic reasonableness of centralized exhaust collection and common NOx control. The evaluation includes not only the SCR reactor itself, but also the representative exhaust collection infrastructure necessary to convey exhaust gases from multiple independently exhausted combustion sources to a common treatment system. This approach provides a conservative engineering evaluation of the most effective technically feasible common-control alternative and establishes the basis for determining whether centralized NOx control is economically reasonable for the representative combustion-source groups.

Because SCR represents the highest-ranked technically feasible representative common-control technology identified in the top-down analysis, it was selected as the basis for the representative economic evaluation. If the conceptual SCR systems are determined to be economically unreasonable, representative common-control technologies providing lower control effectiveness would not be expected to represent more reasonable RACT alternatives.

9.4.2 Representative Common-Control Cost Basis

Representative capital costs for each engineering group were developed using conceptual retrofit designs intended to reflect the complete scope of work necessary to implement centralized post-combustion NOx control within an existing manufacturing facility. Unlike new construction, retrofit implementation requires integration of common control systems into existing buildings, utilities, production equipment, and independently exhausted combustion sources. Consequently, the capital investment extends substantially beyond the purchase price of the NOx control equipment itself.

For each representative engineering group, the estimated capital investment includes conceptual exhaust collection ductwork, branch connections from individual combustion sources, common exhaust headers, induced-draft fans, dampers, structural steel, foundations, electrical distribution, instrumentation, controls integration, access platforms, stack modifications, engineering, construction management, startup, testing, and commissioning. Where SCR is evaluated, the estimate also includes the reactor housing, catalyst modules, reagent storage and delivery systems, ammonia injection grid, catalyst access provisions, and associated safety systems.

Annual operating costs include electrical power for induced-draft fans, routine maintenance, catalyst replacement accrual, reagent consumption, instrumentation calibration, performance testing, inspection, and routine operating support. Because the representative engineering groups contain multiple independently operated combustion sources, the conceptual common-control systems also include additional operating complexity associated with balancing exhaust flows, maintaining draft control, coordinating maintenance outages, and integrating common control systems with existing manufacturing operations.

The representative cost estimates presented herein were developed for comparative RACT screening purposes using engineering scaling relationships, representative retrofit assumptions, and accepted engineering estimating practices. The estimates are intended to evaluate the economic reasonableness of centralized NOx control implementation and should not be interpreted as procurement-level construction estimates or final engineered project costs.

To provide a consistent basis for the representative economic evaluation, conceptual retrofit designs were developed for each engineering group using common engineering assumptions applicable to centralized post-combustion NOx control systems. Because final engineering design was beyond the scope of this RACT evaluation, the conceptual designs were intended to represent the principal infrastructure required to collect, convey, and treat exhaust gases from multiple independently exhausted combustion sources located within each representative manufacturing area. The representative design assumptions used to develop the economic evaluations are summarized in **Table 9-4**.

Table 9-4. Representative Conceptual Design Basis

Conceptual System Component	Representative Assumption
Control Technology	Centralized Selective Catalytic Reduction (SCR)
Exhaust Collection	Common ductwork serving representative combustion-source group
Exhaust Headers	Multiple branch connections from individual combustion sources
Draft Control	New induced-draft fan(s) with variable frequency drives
NOx Control Equipment	SCR reactor with catalyst modules and ammonia injection system
Reagent Storage	Outdoor ammonia or urea storage and delivery system
Structural Requirements	Structural steel supports, equipment platforms, and foundations
Electrical Requirements	Motor control centers, power distribution, instrumentation, and controls integration
Stack Modifications	New or modified common exhaust stack as required
Engineering Scope	Engineering, procurement support, construction management, startup, testing, and commissioning

9.4.3 Group 1 – A-Plant Representative Common-Control Cost Evaluation

Group 1 consists of the A-Plant combustion sources located primarily in Buildings 200, 206, and 210. This group represents the largest concentration of non-boiler natural gas-fired process combustion sources evaluated in this study and includes titanium processing furnaces, Inconel processing equipment, reheat furnaces, die heaters, preheat furnaces, heat-treat furnaces, and related process heating equipment. Because Group 1 was determined to be marginally feasible from an engineering standpoint, a representative centralized SCR system was evaluated for economic reasonableness.

The conceptual common-control system for Group 1 assumes installation of a centralized SCR system serving the A-Plant process combustion area. The required retrofit scope includes multiple branch exhaust connections, extensive exhaust collection ductwork, induced-draft fan capacity, SCR reactor, reagent storage and injection system, structural steel, electrical and controls integration, access provisions, and stack modifications. The evaluation reflects the full retrofit scope necessary to collect and control exhaust from multiple independently exhausted process units, rather than only the cost of the SCR reactor itself.

Table 9-5. Group 1 – A-Plant Representative Common-Control Cost Evaluation

Cost/Evaluation Parameter	Value/Basis
Representative Group	Group 1 – A-Plant
Included Buildings	200, 206, and 210
Representative Emission Units	F023, F024, F025, F026, F027, P054, P087, P100, P107, P125, P154, P177, P230
Representative Control Technology	Centralized SCR
Group PTE NOx	83.73 TPY
2025 Actual NOx Emissions	19.77 TPY
Estimated Common Exhaust Collection Infrastructure	\$7,988,654
Estimated Shared SCR Cost Effectiveness	\$29,510 per ton NOx removed
Representative RACT Determination	Centralized SCR is not economically reasonable for the A-Plant representative group.

9.4.4 Group 2 – S-Plant Representative Common-Control Cost Evaluation

Group 2 consists of the S-Plant combustion sources located in Building 150. This representative group includes multiple heat-treat furnaces, age ovens, and a soaker furnace that support specialized thermal processing operations. Although Group 2 was determined to be marginally feasible from an engineering standpoint, implementation of a representative centralized SCR system would require installation of a common exhaust collection system serving multiple independently exhausted combustion sources. Accordingly, a representative centralized SCR system was evaluated to determine the economic reasonableness of common NOx control for this manufacturing area.

The conceptual common-control system for Group 2 assumes installation of a centralized SCR system serving the S-Plant process combustion area. The representative retrofit scope includes common exhaust headers, collection ductwork, induced-draft fan capacity, SCR reactor, reagent storage and injection equipment, structural steel, electrical and controls integration, access provisions, and stack modifications. The evaluation reflects the complete infrastructure necessary to collect and control exhaust from multiple independently exhausted combustion sources within the S-Plant manufacturing area.

Table 9-6. Group 2 – S-Plant Representative Common-Control Cost Evaluation

Cost/Evaluation Parameter	Value/Basis
Representative Group	Group 2 – S-Plant
Included Buildings	Building 150
Representative Emission Units	P121 (Heat Treat), P121 (Age Oven), P122 (Heat Treat), P122 (Age Oven), P152 (Heat Treat), P152 (Age Oven), P402
Representative Control Technology	Centralized SCR
Group PTE NOx	31.55 TPY
2025 Actual NOx Emissions	4.81 TPY
Estimated Common Exhaust Collection Infrastructure	\$5,159,158
Estimated Shared SCR Cost Effectiveness	\$77,237 per ton NOx removed
Representative RACT Determination	Centralized SCR is not economically reasonable as a representative common-control RACT alternative.

9.4.5 Group 3 – Building 120 Representative Common-Control Cost Evaluation

Group 3 consists of the Building 120 combustion sources, including two heat-treat furnaces and two age ovens serving a dedicated manufacturing area. Although this representative group contains fewer combustion sources than Groups 1 and 2, it was determined to be marginally feasible from an engineering standpoint because installation of a representative centralized SCR system would require common exhaust collection infrastructure, induced-draft fan capacity, structural modifications, and

associated balance-of-plant systems. Accordingly, a representative centralized SCR system was evaluated to determine the economic reasonableness of common NO_x control for this manufacturing area.

The conceptual common-control system for Group 3 assumes installation of a centralized SCR system serving the Building 120 process area. The representative retrofit scope includes common exhaust headers, collection ductwork, induced-draft fan capacity, SCR reactor, reagent storage and injection equipment, structural steel, electrical and controls integration, access provisions, and stack modifications. The evaluation reflects the complete infrastructure necessary to collect and control exhaust from multiple independently exhausted combustion sources within the Building 120 manufacturing area.

Table 9-7. Group 3 – Building 120 Representative Common-Control Cost Evaluation

Cost/Evaluation Parameter	Value/Basis
Representative Group	Group 3 – Building 120
Included Buildings	120
Representative Emission Units	P003 (Heat Treat), P003 (Age Oven), P004 (Heat Treat), P004 (Age Oven)
Representative Control Technology	Centralized SCR
Group PTE NO _x	6.26 TPY
2025 Actual NO _x Emissions	1.27 TPY
Estimated Common Exhaust Collection Infrastructure	\$3,246,024
Estimated Shared SCR Cost Effectiveness	\$101,794 per ton NO _x removed
Representative RACT Determination	Centralized SCR is not economically reasonable for the Building 120 representative group.

9.4.6 Group 4 – H-Plant Representative Common-Control Evaluation

Group 4 consists of the remaining natural gas-fired combustion sources located primarily within Buildings 101, 111, 112A, and 114. As discussed in Section 6, these combustion sources are widely dispersed, operate independently, and are served by numerous individual exhaust systems. Implementation of a representative centralized SCR system would require extensive exhaust collection infrastructure extending across multiple manufacturing buildings, numerous branch duct connections, induced-draft fan systems, structural modifications, electrical distribution, and associated balance-of-plant facilities.

Unlike Groups 1 through 3, Group 4 was determined during the representative engineering evaluation to be not reasonably feasible for centralized common control because of its dispersed multi-building configuration and the extensive exhaust collection system required to convey emissions to a common control device. Accordingly, a detailed representative economic evaluation was not performed. Even if engineering feasibility were assumed, the extensive exhaust collection infrastructure and comparatively low annual NO_x emissions indicate that cost effectiveness would be substantially less favorable than the representative groups evaluated in Sections 9.4.3 through 9.4.5.

Therefore, Group 4 was not carried forward to detailed representative economic evaluation, and centralized SCR is not considered a reasonable representative common-control RACT alternative for this combustion-source group.

Table 9-8. Group 4 – H-Plant Representative Common-Control Cost Evaluation

Cost/Evaluation Parameter	Value/Basis
Representative Group	Group 4 – H-Plant / Remaining Small Furnace Group
Included Buildings	Buildings 101, 111, 112A, and 114
Representative Emission Units	F003, F004, F006, F007, F008, F010, F011, F012, F015, F016, P434, F017, F018, F019, F020, P105
Representative Control Technology	Centralized SCR
Group PTE NOx	44.96 TPY
2025 Actual NOx Emissions	7.16 TPY
Estimated Common Exhaust Collection Infrastructure	\$8,638,972
Estimated Shared SCR Cost Effectiveness	\$35,406 per ton NOx removed
Representative RACT Determination	Centralized SCR is not economically reasonable as a representative common-control RACT alternative.

9.4.7 Summary of Representative Common-Control Economic Evaluation

The representative economic evaluations demonstrate that implementation of centralized SCR systems for the retained representative combustion-source groups would require substantial capital investment to construct common exhaust collection systems, install centralized post-combustion NOx control equipment, and integrate new control infrastructure into existing manufacturing operations. For each representative group, the majority of the required capital investment is associated with exhaust collection infrastructure, including common ductwork, induced-draft fans, structural modifications, electrical systems, controls integration, and related balance-of-plant facilities, rather than the SCR equipment itself.

Although Groups 1 through 3 were determined to be marginally feasible from an engineering standpoint and therefore advanced to economic evaluation, the resulting representative cost-effectiveness values substantially exceed levels typically considered economically reasonable for retrofit NOx controls. The representative evaluations further demonstrate that the distributed arrangement of independently exhausted combustion sources significantly increases the cost of implementing centralized common-control systems while providing comparatively limited incremental annual NOx reductions.

Accordingly, the representative economic evaluation demonstrates that centralized SCR systems do not represent economically reasonable RACT alternatives for the remaining natural gas-fired combustion-source groups. The representative evaluations support the conclusion that implementation of common post-combustion NOx controls would require disproportionate capital investment relative to the achievable environmental benefit and therefore do not satisfy the economic feasibility component of the top-down RACT analysis.

10. Cost-Effectiveness Comparison

The technically feasible NO_x control technologies identified in the preceding sections were further evaluated based on relative cost effectiveness and incremental NO_x reduction capability under representative operating conditions for Boilers B008 and B009. Consistent with top-down RACT methodology, the evaluation considered both the magnitude of achievable NO_x reductions and the economic and operational impacts associated with retrofit implementation for existing natural gas-fired package boilers.

For the remaining natural gas-fired combustion sources evaluated using the representative engineering groups developed in Section 6, cost effectiveness was evaluated using representative conceptual common-control systems rather than individual combustion units. As demonstrated in Section 9.4, centralized SCR systems for Groups 1 through 3 were associated with substantial exhaust collection infrastructure costs and correspondingly high cost-effectiveness values, while Group 4 was eliminated during the engineering feasibility evaluation and therefore was not carried forward to detailed economic analysis. These representative evaluations establish that centralized common-control systems do not represent economically reasonable RACT alternatives for the remaining combustion-source groups.

Cost-effectiveness evaluations presented in this section were developed using current operating information, recent emissions testing results, representative 2025 actual operating conditions, and study-level engineering cost assumptions applicable to retrofit installations. The evaluation focuses on representative 2025 actual operating conditions in order to provide a realistic assessment of achievable annual NO_x reductions and corresponding economic impacts associated with each control technology option.

For existing boilers operating on natural gas with established combustion optimization practices already in place, the remaining incremental NO_x reductions achievable through major retrofit technologies must be considered in the context of substantial retrofit integration requirements, outage coordination, operational impacts, and long-term annualized cost obligations. Accordingly, the cost-effectiveness evaluation considers not only theoretical control efficiency, but also the practical economic reasonableness of implementing combustion retrofit or post-combustion controls on existing industrial boiler systems.

The resulting cost-effectiveness values are intended to support comparative RACT evaluation and control-technology screening rather than procurement-level financial analysis. Estimated annualized costs and dollars-per-ton values were developed using study-level engineering assumptions, available retrofit information, U.S. EPA cost methodology concepts, and engineering judgment applicable to retrofit NO_x control projects for existing package boilers.

Although high-efficiency post-combustion technologies such as SCR may achieve substantial NO_x reduction capability in principle, the economic evaluation must also consider the incremental emission reductions achievable beyond existing controlled operation together with the retrofit complexity and operational impacts associated with implementation. Accordingly, cost effectiveness was evaluated as one component of the overall source-specific RACT determination for Boilers B008 and B009.

Cost-effectiveness calculations were developed using representative 2025 actual NO_x emissions for Boilers B008 and B009 together with study-level control efficiency assumptions for each evaluated technology. Annual NO_x reductions were estimated by applying the assumed control efficiency to the corresponding 2025 actual annual NO_x emissions for each boiler. Resulting annualized costs were then divided by the estimated annual NO_x reductions to calculate dollars-per-ton cost effectiveness values for comparative RACT evaluation purposes.

For comparative engineering evaluation, cost-effectiveness calculations were developed using both representative 2025 actual operating conditions and each boiler's potential-to-emit (PTE) basis. The representative 2025 actual operating basis provides the primary basis for evaluating the economic reasonableness of retrofit NO_x control technologies because it reflects current facility operation and the corresponding annual NO_x reductions achievable under normal operating conditions. The PTE-based calculations assume continuous operation at permitted capacity and are presented solely as a comparative sensitivity analysis and to facilitate comparison with previous screening evaluations. Controlled emission rates presented in **Table 10-2** were estimated by applying representative control reduction efficiencies to the measured April 2026 baseline emission rates of approximately 0.125 lb/MMBtu for Boiler B008 and 0.149 lb/MMBtu for Boiler B009. These values are screening-level engineering estimates intended for comparative RACT evaluation only and do not represent guaranteed vendor performance or proposed permit limits. The comparative engineering-economic evaluations presented herein are intended to support source-specific RACT screening and do not represent final engineered design studies, vendor guarantees, or enforceable compliance determinations.

Table 10-1. Cost Effectiveness Relative to 2025 Actual Baseline and PTE Sensitivity

Cost effectiveness was evaluated primarily using representative 2025 actual operating emissions for Boilers B008 and B009, consistent with the objective of evaluating comparative RACT feasibility under representative current operating conditions. Potential-to-emit (PTE) operating assumptions were evaluated separately as a comparative sensitivity analysis to illustrate the effect of theoretical maximum utilization on calculated cost effectiveness. Representative current operating conditions were used as the primary comparative RACT screening basis, while PTE assumptions were evaluated separately to illustrate the sensitivity of calculated cost effectiveness to theoretical maximum utilization.

Technology	Boiler	Assumed Reduction	Annualized Cost (\$/yr)	2025 Actual Baseline (TPY)	NOx Removed Actual (TPY)	Actual-Basis Cost Effectiveness (\$/ton)	PTE Baseline (TPY)	NOx Removed PTE (TPY)	PTE-Basis Cost Effectiveness (\$/ton)
Combustion tune-up / burner optimization	B008	10.0%	\$26,207	11.46	1.15	\$22,868	64.91	6.49	\$4,037
Combustion tune-up / burner optimization	B009	10.0%	\$26,207	10.16	1.02	\$25,794	64.91	6.49	\$4,037
Oxygen trim / controls modernization	B008	15.0%	\$67,828	11.46	1.72	\$39,458	64.91	9.74	\$6,966
Oxygen trim / controls modernization	B009	15.0%	\$67,828	10.16	1.52	\$44,507	64.91	9.74	\$6,966
Low excess air optimization	B008	10.0%	\$38,414	11.46	1.15	\$33,520	64.91	6.49	\$5,918
Low excess air optimization	B009	10.0%	\$38,414	10.16	1.02	\$37,809	64.91	6.49	\$5,918
FGR retrofit / fan and duct modifications	B008	37.5%	\$253,545	11.46	4.30	\$58,998	64.91	24.34	\$10,416
FGR retrofit / fan and duct modifications	B009	37.5%	\$253,545	10.16	3.81	\$66,547	64.91	24.34	\$10,416
LNB/ULNB with IFGR and controls	B008	65%	\$376,217	11.46	5.35	\$70,321	64.91	30.31	\$12,413
LNB/ULNB with IFGR and controls	B009	65%	\$376,217	10.16	4.74	\$79,370	64.91	30.31	\$12,413
SNCR	B008	37.5%	\$284,838	11.46	4.30	\$66,280	64.91	24.34	\$11,702
SNCR (not technically feasible)	B009	37.5%	\$284,838	10.16	3.81	\$74,761	64.91	24.34	\$11,702
SCR	B008	85.0%	\$505,978	11.46	9.74	\$51,943	64.91	55.17	\$9,171
SCR	B009	85.0%	\$505,978	10.16	8.64	\$58,589	64.91	55.17	\$9,171

Note: 2025 actual baseline emissions are 11.46 TPY for B008 and 10.16 TPY for B009. PTE baseline is 64.91 TPY per boiler. Actual-basis cost effectiveness is the primary representative cost-effectiveness screen; PTE-basis values are included solely as a comparative sensitivity evaluation using theoretical maximum utilization assumptions and are not intended to represent representative current operating conditions.

Table 10-2. Approximate Controlled Emission Rates and Comparative Cost Effectiveness

Technology	Boiler	Reduction	Annualized Cost	Controlled Rate (lb/MMBtu)	Meets 0.08?	Actual NO _x Removed (TPY)	Actual \$/ton	PTE NO _x Removed (TPY)	PTE \$/ton	Decision Consideration
Tune-up / burner optimization	B008	10.0%	\$26,207	0.113	No	1.15	\$22,868	6.49	\$4,037	Work-practice baseline
Tune-up / burner optimization	B009	10.0%	\$26,207	0.134	No	1.02	\$25,794	6.49	\$4,037	Work-practice baseline
Oxygen trim / controls	B008	15.0%	\$67,828	0.106	No	1.72	\$39,458	9.74	\$6,966	Incremental control
Oxygen trim / controls	B009	15.0%	\$67,828	0.127	No	1.52	\$44,507	9.74	\$6,966	Incremental control
Low excess air	B008	10.0%	\$38,414	0.113	No	1.15	\$33,520	6.49	\$5,918	Operationally constrained
Low excess air	B009	10.0%	\$38,414	0.134	No	1.02	\$37,809	6.49	\$5,918	Operationally constrained
FGR retrofit	B008	37.5%	\$253,545	0.078	Potentially	4.30	\$58,998	24.34	\$10,416	Requires OEM confirmation
FGR retrofit	B009	37.5%	\$253,545	0.093	Potentially	3.81	\$66,547	24.34	\$10,416	Does not reach 0.08
LNB/ULNB + IFGR + controls	B008	65%	\$163,300	0.044 ⁵	Yes	7.45	\$21,922	42.19	\$3,870	Major combustion-system retrofit
LNB/ULNB + IFGR + controls	B009	65%	\$163,300	0.052	Yes	6.60	\$24,727	42.19	\$3,870	Major combustion-system retrofit
SNCR	B008	37.5%	\$284,838	0.078	Uncertain	4.30	\$66,280	24.34	\$11,702	Not technically feasible
SNCR	B009	37.5%	\$284,838	0.093	Uncertain	3.81	\$74,761	24.34	\$11,702	Not technically feasible
SCR	B008	85.0%	\$505,978	0.019	Demonstrated	9.74	\$51,943	55.17	\$9,171	Major capital-intensive retrofit
SCR	B009	85.0%	\$505,978	0.022	Demonstrated	8.64	\$58,589	55.17	\$9,171	Major capital-intensive retrofit

Note: Controlled emission rates were estimated by applying representative screening-level control reduction assumptions to measured April 2026 baseline emission rates of approximately 0.125 lb/MMBtu for Boiler B008 and 0.149 lb/MMBtu for Boiler B009. 'Potentially' indicates that the referenced emission level may be achievable based on screening-level engineering evaluation but would require additional engineering confirmation, combustion evaluation, or vendor review. 'Demonstrated' indicates established commercial capability on comparable combustion sources. These values are approximate screening-level estimates for comparative RACT evaluation purposes and do not represent guaranteed vendor performance or proposed permit limits. The comparative screening values presented herein are intended for engineering-economic RACT evaluation purposes and do not represent guaranteed vendor performance levels, final engineered design commitments, or proposed enforceable permit limits

⁵ Controlled emission rates for LNB/ULNB + FGR + controls were estimated using a representative screening-level NO_x reduction assumption of approximately 46.7% relative to measured April 2026 baseline stack test emission rates for each boiler. Estimated controlled emission rates were calculated as follows: B008: 0.125 lb/MMBtu × (1 – 0.467) = 0.067 lb/MMBtu; B009: 0.149 lb/MMBtu × (1 – 0.467) = 0.079 lb/MMBtu. These values are approximate comparative engineering estimates for RACT evaluation purposes and do not represent guaranteed vendor performance or proposed permit limits.

The cost-effectiveness comparisons presented in **Tables 10-1 and 10-2** apply specifically to the source-specific retrofit alternatives evaluated for Boilers B008 and B009. The remaining natural gas-fired combustion sources were evaluated using the representative engineering group methodology described in Sections 6 through 9. Because equipment-specific combustion retrofit technologies (e.g., low-NO_x burners, flue gas recirculation, oxygen trim, and combustion controls optimization) cannot be evaluated on a representative common-control basis, the representative economic evaluation focused on centralized SCR as the highest-ranked technically feasible common-control technology. As demonstrated in Section 9.4, representative centralized SCR systems were determined to be economically unreasonable for Groups 1 through 3, while Group 4 was eliminated during the engineering feasibility evaluation. Accordingly, no representative common-control technology remains for further consideration under the top-down RACT analysis.

11. RACT Determination

The purpose of this section is to identify Reasonably Available Control Technology (RACT) for the natural gas-fired combustion sources subject to OAC Chapter 3745-110 based on the engineering, technical feasibility, and economic evaluations presented in the preceding sections of this study. The RACT evaluation was performed using a combination of source-specific analyses for Boilers B008 and B009 and representative engineering evaluations for the remaining natural gas-fired combustion sources. This approach recognizes the significant differences in combustion equipment design, process function, operating characteristics, and physical configuration between the utility boilers and the numerous process combustion units distributed throughout the facility.

For Boilers B008 and B009, a source-specific top-down RACT analysis was performed because these units represent the largest individual NO_x emission sources at the facility and are physically suited for evaluation of conventional combustion and post-combustion NO_x control technologies. The remaining natural gas-fired combustion sources consist of numerous independently operated furnaces, ovens, heat-treat units, die heaters, and other process combustion equipment serving diverse manufacturing operations. Because these units are widely distributed throughout the facility and exhibit similar engineering characteristics within defined manufacturing areas, representative engineering groups were established to evaluate the technical feasibility and economic reasonableness of common-control strategies applicable to each group.

11.1 Source-Specific RACT Determination – Boilers B008 and B009

Consistent with the top-down RACT methodology outlined in OAC 3745-110-03(J), the technically feasible NO_x control technologies identified for Boilers B008 and B009 were comparatively evaluated to determine the most appropriate source-specific RACT. The evaluation considered control effectiveness, technical feasibility, retrofit complexity, operational impacts, combustion-system integration requirements, implementation considerations, and comparative cost effectiveness under representative operating conditions for the subject natural gas-fired package boilers. The engineering and economic evaluations supporting these determinations are presented in Sections 6 through 10 of this study.

The evaluation demonstrated that Selective Catalytic Reduction (SCR) is technically feasible in principle for industrial boiler applications. However, implementation would require substantial retrofit integration including catalyst reactor installation, ductwork reconstruction, reagent storage and handling systems, induced draft fan modifications, controls integration, structural modifications, outage coordination, and long-term catalyst management. Although SCR provides the highest theoretical NO_x reduction efficiency, the technology represents the most complex retrofit alternative evaluated and was determined not to represent the most reasonable source-specific RACT alternative for Boilers B008 and B009.

Selective Non-Catalytic Reduction (SNCR) was also evaluated. The engineering evaluation determined that the existing package boilers do not provide the furnace temperature profile, residence time, or reagent mixing characteristics necessary to support reliable SNCR performance. Accordingly, SNCR was eliminated from further consideration as a technically feasible RACT alternative.

The engineering evaluation further demonstrated that Low-NO_x Burners (LNB/ULNB) integrated with induced Flue Gas Recirculation (FGR) and modern combustion controls represent the most appropriate combustion-side retrofit technology for Boilers B008 and B009. This technology provides significant NO_x reduction while maintaining the operational flexibility necessary for the facility's variable steam demand and was determined by Ohio EPA to represent Reasonably Available Control Technology (RACT) based upon the technical and economic evaluations presented in this study.

Implementation of LNB/ULNB burners with integrated FGR will require replacement of the existing burner assemblies, installation of combustion air and flue gas recirculation equipment, combustion controls integration, electrical modifications, startup and commissioning activities, combustion tuning, operator

training, and post-installation performance verification. Because these activities require substantial engineering design, equipment procurement, planned boiler outages, and coordination with facility operations, implementation will occur in accordance with the schedule presented in Section 12. Consistent with OAC 3745-110-04(B)(1), the facility will implement the approved RACT controls as expeditiously as practicable following Ohio EPA approval of the final RACT determination.

Operational optimization measures, including continued firing of natural gas, implementation of Good Combustion Practices, annual combustion tune-ups, combustion controls optimization, oxygen trim optimization, low excess air operation, appropriate recordkeeping, and continued monitoring of boiler operating conditions, remain integral components of the overall RACT strategy. These measures support continued efficient boiler operation and sustained NO_x minimization both before and after installation of the combustion retrofit.

Accordingly, the source-specific RACT determination for Boilers B008 and B009 consists of installation of LNB/ULNB burners with integrated FGR and associated combustion controls together with continued implementation of Good Combustion Practices, annual combustion tune-ups, combustion optimization, and ongoing operational monitoring. The representative implementation schedule presented in Section 12 provides a reasonable engineering sequence for detailed design, permitting, procurement, installation, startup, commissioning, and compliance demonstration.

The representative engineering and economic evaluations presented in Sections 6 through 10 also demonstrate that centralized common-control systems do not represent technically feasible or economically reasonable RACT alternatives for the remaining natural gas-fired combustion sources evaluated using the representative engineering methodology. Groups 1 through 3 require extensive exhaust collection systems and associated balance-of-plant infrastructure resulting in cost effectiveness values that are not economically reasonable for retrofit implementation. Group 4 was eliminated during the engineering feasibility evaluation because its dispersed combustion-source configuration is not compatible with representative centralized control. Accordingly, no representative common-control technology is identified as RACT for the remaining combustion-source groups evaluated in this study.

The source-specific RACT evaluation for Boilers B008 and B009 is summarized in **Table 11-1**.

Table 11-1. Comparative Evaluation of Source-Specific RACT Control Options for Boilers B008 and B009

Control Technology	Technical Feasibility Conclusion	Relative Economic/Operational Considerations	RACT Evaluation Outcome
Continued combustion optimization, annual tune-ups, and good combustion practices	Technically feasible and currently implemented as part of normal boiler operation	Minimal operational disruption; supports ongoing combustion efficiency and NOx minimization	Retained as foundational operational RACT measure
Oxygen trim / combustion controls optimization	Technically feasible as incremental combustion optimization measure	Moderate instrumentation and controls integration requirements; limited standalone NOx reduction capability	Retained as supplemental operational optimization measure
Low excess air optimization	Technically feasible within combustion stability and CO operating constraints	Limited incremental NOx reduction potential; constrained by flame stability and boiler turndown requirements	Retained as supplemental operational optimization measure
FGR retrofit	Technically feasible in principle but requires substantial fan, ductwork, and combustion-system modifications	Significant retrofit integration requirements and outage coordination; uncertain standalone ability to achieve low NOx rates	Not selected as standalone RACT control technology
LNB/ULNB with integrated FGR and combustion controls	Technically feasible combustion retrofit option for the subject boilers	Major combustion-system retrofit requiring burner replacement, controls integration, commissioning, and outage scheduling; significant annualized cost impacts	Selected RACT.
SNCR	Not technically feasible for the subject boilers	Subject boilers do not demonstrate suitable furnace temperature and residence-time characteristics necessary for reliable SNCR operation	Eliminated from further RACT consideration
SCR	Technically feasible in principle	Highest retrofit complexity and annualized cost; requires catalyst reactor, reagent infrastructure, ductwork modifications, and substantial balance-of-plant integration	Not identified as the most reasonable source-specific RACT option under the representative operating conditions evaluated in this study for the subject boilers
Fuel switching	Not applicable	Boilers already operate on natural gas, the preferred low-NOx gaseous fuel	Eliminated from further RACT consideration
Process modification / steam demand reduction	Operationally possible but dependent on facility production requirements	Does not directly reduce boiler emission factor (lb/MMBtu); dependent on external process demand	Not selected as primary RACT control strategy

11.2 Evaluation of NO_x Control Technologies Identified in OAC 3745-110-03(J)(1)(h)

Consistent with Ohio EPA's review comments and the requirements of OAC 3745-110-03(J)(1)(h), each NO_x control technology identified in the rule was evaluated for applicability to the four representative combustion-source engineering groups developed in this study. The objective of this evaluation is to determine whether each control technology represents a technically feasible and economically reasonable RACT alternative for the representative combustion-source groups or whether the technology should be eliminated based on engineering limitations, process incompatibility, or lack of representative applicability.

The following subsections evaluate each identified NO_x control technology using the representative engineering methodology developed in Sections 6 through 10. For each technology, the discussion addresses its applicability to Group 1 (A-Plant), Group 2 (S-Plant), Group 3 (Building 120), and Group 4 (H-Plant and remaining dispersed combustion sources), followed by a representative engineering determination regarding its suitability as a common-control RACT technology.

11.2.1 Low-NO_x Burners (LNB)

Low-NO_x burners (LNB) reduce NO_x emissions by controlling flame geometry, fuel-air mixing, peak flame temperature, and oxygen availability during combustion. The applicability of LNB technology was evaluated for each of the four representative combustion-source engineering groups developed in this study to determine whether LNB could reasonably serve as a representative control technology for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 represents the largest concentration of natural gas-fired process combustion equipment within Buildings 200, 206, and 210, including titanium processing furnaces, Inconel processing equipment, reheat furnaces, die heaters, heat-treat furnaces, and related manufacturing combustion sources. Although certain individual combustion units within this group may utilize burner assemblies that could theoretically be replaced with commercially available low-NO_x burners, the group consists of numerous independently designed process heating systems performing substantially different manufacturing functions. Burner geometries, firing rates, furnace configurations, process temperature requirements, and combustion control philosophies vary significantly among the individual units.

Implementation of LNB technology as a representative common-control strategy would therefore require individual engineering evaluation and custom retrofit design for each combustion source rather than a single representative burner replacement applicable across the engineering group. Consequently, LNB does not constitute a practical representative common-control technology for Group 1. However, LNB technology remains technically feasible on a source-specific basis for selected combustion units where compatible burner configurations and process operating requirements can be demonstrated.

Group 2 – S-Plant

Group 2 consists primarily of heat-treat furnaces, aging ovens, and associated process combustion equipment located within Building 150. These combustion sources likewise employ multiple furnace designs, burner arrangements, and process-specific operating conditions that were developed to satisfy individual manufacturing requirements. Although selected units may be physically capable of accommodating low-NO_x burner replacement, implementation would require individual burner selection, combustion tuning, control integration, and verification that required metallurgical heating characteristics are maintained.

Because no common burner configuration exists that can be reasonably applied across the representative combustion-source group, LNB technology is not considered an appropriate representative common-control alternative for Group 2. Any future application of LNB technology would require source-specific engineering evaluation rather than implementation as a centralized representative retrofit strategy.

Group 3 – Building 120

Group 3 consists of the process combustion equipment located within Building 120, including furnaces and associated natural gas-fired heating units that support specialized manufacturing operations. The relatively limited number of combustion sources within this group does not eliminate the need for individual engineering evaluation because each combustion unit performs distinct process functions with unique combustion characteristics and production requirements.

Although replacement of individual burner assemblies may be technically feasible for certain units, no representative low-NO_x burner configuration can be identified that would reasonably apply across the entire engineering group. Accordingly, LNB technology is not considered an appropriate representative common-control technology for Group 3. Source-specific burner replacement may remain feasible for individual units where supported by detailed engineering evaluation and vendor recommendations.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes the dispersed combustion sources located primarily within the H-Plant and other remaining manufacturing areas not represented by Groups 1 through 3. These combustion units are generally smaller process heaters, furnaces, and specialty manufacturing equipment distributed throughout multiple buildings with widely varying operating schedules, firing rates, and process objectives. The diversity and dispersion of these combustion sources preclude development of a representative low-NO_x burner retrofit applicable to the engineering group as a whole.

Implementation of LNB technology would require independent engineering review, burner selection, combustion testing, and process verification for each individual combustion source. Accordingly, LNB technology is not considered a technically appropriate representative common-control strategy for Group 4. Where technically justified, however, LNB technology may remain feasible for selected individual combustion units following source-specific engineering evaluation.

Representative Technology Determination

Low-NO_x burners were evaluated for each representative combustion-source group. Although the technology may be technically feasible for selected individual combustion units, the diversity of equipment designs, combustion characteristics, process requirements, and burner configurations precludes development of a representative common-control retrofit applicable across any of the four engineering groups. Therefore, LNB technology is not identified as a representative common-control RACT alternative for the grouped combustion sources evaluated in this study. Source-specific application of LNB technology remains appropriate where warranted by individual equipment design and separate RACT evaluation, as demonstrated for Boilers B008 and B009.

11.2.2 Ultra-Low-NO_x Burners (ULNB)

Ultra-Low-NO_x Burners (ULNB) are advanced combustion systems that further reduce NO_x formation through staged combustion, optimized flame geometry, and enhanced fuel-air mixing. Similar to conventional LNB technology, ULNB applicability was evaluated for each representative engineering group to determine whether the technology could serve as a representative common-control strategy for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of numerous independently designed process furnaces, heat-treat units, die heaters, and specialty combustion systems serving different manufacturing processes. Although ULNB technology may be technically feasible for selected individual combustion units, the diversity of burner designs, furnace configurations, and process heating requirements precludes application of a common ULNB retrofit across the representative group. Implementation would require source-specific engineering and vendor evaluation for each combustion unit.

Group 2 – S-Plant

The combustion sources within Building 150 utilize multiple furnace and oven configurations designed for specific heat-treating operations. Retrofit with ULNB technology would require individual burner replacement, combustion tuning, and confirmation that required metallurgical heating characteristics are maintained. Accordingly, ULNB technology is not considered a representative common-control strategy for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment with combustion systems designed to satisfy unique manufacturing requirements. While selected units may be compatible with ULNB replacement burners, no representative burner configuration can reasonably be applied across the engineering group. Any future ULNB installation would require source-specific engineering evaluation.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 consists primarily of dispersed, relatively small process combustion units located throughout multiple manufacturing areas. The wide variation in burner size, furnace configuration, and operating schedules prevents development of a representative ULNB retrofit applicable to the group as a whole. Consequently, ULNB technology is not considered an appropriate representative common-control alternative for Group 4.

Representative Technology Determination

Ultra-Low-NO_x burners were evaluated for each representative combustion-source group. Although technically feasible for certain individual combustion units, the technology cannot be implemented as a representative common-control strategy because of the diversity of equipment designs, process functions, and combustion system configurations. Accordingly, ULNB technology is not identified as a representative common-control RACT alternative for the grouped combustion sources evaluated in this study. Source-specific application of ULNB technology remains appropriate where supported by individual equipment design and engineering evaluation.

11.2.3 Close-Coupled or Separated Over-Fire Ports

Close-coupled or separated over-fire air ports reduce NO_x formation by staging combustion air above the primary burner zone. These systems are generally applied to larger furnaces or boilers having sufficient combustion chamber volume and suitable internal geometry to establish distinct primary and secondary combustion zones.

Group 1 – A-Plant

The A-Plant group consists of process furnaces, reheat furnaces, heat-treat units, die heaters, and other specialized combustion equipment having individual furnace geometries and process-specific burner arrangements. These units were not designed with the combustion chamber volume, wall configuration, or air distribution systems necessary to accommodate over-fire air ports. Retrofitting such systems would require major furnace reconstruction and could adversely affect product heating uniformity and process temperature control. Accordingly, over-fire air is not technically feasible as a representative control strategy for Group 1.

Group 2 – S-Plant

The S-Plant group includes heat-treat furnaces, age ovens, and a soaker furnace designed to maintain controlled metallurgical heating profiles. Installation of over-fire air ports would require substantial modification of the furnace walls, combustion air systems, and burner controls. The process units do not provide a common furnace configuration suitable for staged-air retrofit, and the resulting changes in heat distribution could interfere with required process conditions. Therefore, over-fire air is not technically feasible for Group 2.

Group 3 – Building 120

The Building 120 group consists of relatively small heat-treat and age ovens with compact combustion chambers and source-specific burner systems. These units lack the internal space and combustion-zone separation needed for effective close-coupled or separated over-fire air operation. Installation would require fundamental redesign of the furnace combustion systems rather than a practicable retrofit. Accordingly, this technology is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 contains dispersed reheat, preheat, and process furnaces of varying size and design. Many are relatively small units with compact combustion chambers and independent burner arrangements. The equipment is not configured for staged-air combustion, and installation of over-fire air ports would require extensive unit-specific reconstruction. Consequently, this technology is not technically feasible as either a representative common-control strategy or a generally applicable source-specific retrofit for Group 4.

Representative Technology Determination

Close-coupled and separated over-fire air ports are not technically feasible for the four representative engineering groups. The process furnaces and ovens lack the furnace volume, geometry, and air-distribution configuration necessary to support staged-air combustion, and implementation would require major reconstruction of individual units. Therefore, this technology is eliminated from further RACT consideration for the grouped combustion sources.

11.2.4 Flue Gas Recirculation (FGR)

Flue Gas Recirculation (FGR) reduces thermal NO_x formation by recirculating a controlled portion of cooled flue gas back to the combustion zone, thereby reducing peak flame temperatures and oxygen concentrations during combustion. The applicability of FGR was evaluated for each representative combustion-source engineering group to determine whether it could serve as a representative NO_x control technology for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of numerous independently operated process furnaces, heat-treat furnaces, reheat furnaces, die heaters, and specialty process combustion units having different firing rates, combustion chamber configurations, and process temperature requirements. Implementation of FGR would require installation of dedicated recirculation ductwork, fans, dampers, burner modifications, combustion controls, and performance verification for each individual combustion unit. Because these combustion sources do not share common burner designs or exhaust configurations, FGR cannot be implemented as a representative common-control strategy for the engineering group.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces, aging ovens, and associated process heating equipment designed to satisfy specific metallurgical requirements. Application of FGR would require source-specific burner modifications, recirculation ductwork, combustion controls, and combustion tuning while maintaining required process heating characteristics. Consequently, FGR is not considered a technically feasible representative common-control technology for Group 2.

Group 3 – Building 120

Group 3 contains specialized process combustion equipment having unique furnace configurations and operating characteristics. Although FGR may be technically feasible for selected individual combustion units, no representative recirculation system can reasonably be applied across the engineering group because of differences in equipment design, firing characteristics, and process requirements. Implementation would therefore require individual engineering evaluation for each combustion source.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 consists primarily of small, dispersed combustion units located throughout multiple manufacturing buildings. The physical separation of these combustion sources, together with their relatively small size and diverse operating schedules, makes installation of representative FGR systems impractical. Source-specific retrofit would require substantial modifications that are not representative of the engineering group as a whole.

Representative Technology Determination

Flue Gas Recirculation was evaluated for each representative combustion-source engineering group. Although FGR may be technically feasible for selected individual combustion units, implementation would require extensive source-specific engineering, dedicated recirculation systems, burner modifications, combustion controls integration, and performance optimization for each affected unit. Accordingly, FGR is not identified as a technically feasible representative common-control RACT alternative for the grouped combustion sources evaluated in this study.

11.2.5 Low-NO_x Burners with External Flue Gas Recirculation (LNB + External FGR)

The combination of Low-NO_x Burners (LNB/ULNB) with external Flue Gas Recirculation (FGR) is an established combustion-control technology capable of achieving substantially greater NO_x reductions than either technology alone. By combining staged combustion with recirculated flue gas, peak flame temperatures are reduced while maintaining combustion efficiency. The applicability of this technology was evaluated for each representative combustion-source engineering group to determine whether it could reasonably serve as a representative common-control strategy for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of numerous independently operated process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units having different burner designs, combustion chamber geometries, firing rates, and process temperature requirements. Implementation of LNB with external FGR would require replacement of existing burner assemblies together with installation of dedicated flue gas recirculation ductwork, recirculation fans, dampers, combustion controls, instrumentation, electrical modifications, and source-specific combustion tuning for each individual combustion unit. Because no common combustion configuration exists across the representative engineering group, the technology cannot be implemented as a representative common-control retrofit.

Group 2 – S-Plant

The combustion sources comprising Group 2 consist primarily of heat-treat furnaces and aging ovens designed to maintain closely controlled metallurgical heating conditions. Installation of LNB with external FGR would require individual burner replacement, recirculation system design, controls integration, and verification that the modified combustion systems continue to satisfy required heating profiles and product quality specifications. Accordingly, implementation would require source-specific engineering for each combustion unit and is not considered a representative common-control strategy for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment serving unique manufacturing operations. Although selected combustion units may theoretically be capable of accommodating LNB with external FGR, substantial engineering modifications would be required for each individual furnace because of differences in burner arrangements, combustion chamber configuration, and process operating requirements. A representative retrofit applicable across the engineering group therefore cannot be developed.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 consists primarily of small, dispersed combustion units distributed throughout multiple manufacturing buildings. The relatively small size of many combustion units, together with their physical separation and diverse operating characteristics, makes installation of LNB with external FGR impractical as a representative common-control strategy. Each combustion unit would require independent engineering evaluation, burner replacement, recirculation equipment, controls integration, and combustion optimization, eliminating the practicality of a representative group retrofit.

Representative Technology Determination

Low-NOx Burners with external Flue Gas Recirculation were evaluated for each representative combustion-source engineering group. Although the technology is technically feasible for certain individual combustion units, implementation across the representative engineering groups would require extensive source-specific engineering, burner replacement, dedicated recirculation systems, combustion controls integration, and performance verification for each individual combustion source. Accordingly, LNB with external FGR is not identified as a technically feasible representative common-control RACT alternative for the grouped combustion sources evaluated in this study.

It should be noted, however, that this conclusion applies only to the representative combustion-source groups evaluated under the engineering methodology developed in this study. As discussed in Section 11.1, Ohio EPA determined that LNB/ULNB with integrated FGR represents Reasonably Available Control Technology for the two subject utility boilers, Boilers B008 and B009, based upon the source-specific technical and economic evaluation performed for those units. Those boilers were evaluated separately because of their size, configuration, and operating characteristics and are not representative of the remaining grouped process combustion sources.

11.2.6 Burners Out of Service

Removal of burners from service reduces NOx emissions by permanently eliminating combustion from the affected emission units. This approach is not considered an emission control technology, but rather a reduction in process capacity through elimination of combustion equipment. The applicability of this approach was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 includes numerous process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty combustion units that support titanium and high-temperature alloy manufacturing operations. Each combustion unit performs a specific production function and was installed to satisfy established manufacturing requirements. Removal of burners from service would permanently reduce available process heating capacity and directly affect production capability. Accordingly, this approach is not technically feasible for Group 1 because it represents process curtailment rather than emission control.

Group 2 – S-Plant

The combustion units comprising Group 2 provide heat-treating and aging operations necessary to achieve required metallurgical properties. Removing burners from service would eliminate essential manufacturing capability and prevent normal operation of the associated process equipment. Consequently, this approach is not technically feasible as a RACT alternative for Group 2.

Group 3 – Building 120

Group 3 consists of specialized process heating equipment supporting unique manufacturing operations. Permanent removal of burners from service would eliminate the process heating necessary for continued operation of these units and is therefore inconsistent with normal facility production. Accordingly, this approach is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process combustion units serving individual manufacturing operations throughout the facility. Although individual units may operate intermittently, each provides process heating necessary to support production demands. Permanent removal of burners from service would reduce manufacturing flexibility and available process capacity rather than control NO_x emissions. Therefore, this approach is not technically feasible for Group 4.

Representative Technology Determination

Removal of burners from service was evaluated for each representative combustion-source engineering group. This approach does not constitute an emission control technology, but instead permanently reduces available manufacturing capacity through elimination of process combustion equipment. Because RACT is intended to identify reasonably available emission control measures while allowing continued operation of existing emission units, removal of burners from service is not considered a technically feasible RACT alternative for the representative combustion-source groups evaluated in this study.

11.2.7 Steam or Water Injection

Steam or water injection reduces thermal NO_x formation by lowering peak flame temperatures through the introduction of steam or water into the combustion zone. This technology has historically been applied primarily to combustion turbines and selected industrial combustion systems specifically designed to accommodate fluid injection. The applicability of steam or water injection was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty combustion equipment designed to achieve precise process temperatures and controlled heating rates. These combustion systems were not designed to accommodate steam or water injection, and implementation would require extensive modification of burners, controls, and associated process equipment. In addition, introduction of steam or water could adversely affect combustion stability, furnace temperature uniformity, and product quality. Accordingly, steam or water injection is not technically feasible for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 support heat-treating and aging operations requiring closely controlled metallurgical heating conditions. Introduction of steam or water into the combustion process could alter furnace heat transfer characteristics, reduce process temperature stability, and affect the metallurgical properties of finished products. Because the existing combustion systems were not designed for this technology, steam or water injection is not considered technically feasible for Group 2.

Group 3 – Building 120

Group 3 consists of specialized process heating equipment designed to satisfy unique manufacturing requirements. Retrofitting these units with steam or water injection systems would require substantial burner modifications, additional utility systems, controls integration, and process validation. The resulting operational impacts outweigh any potential NO_x reduction benefits, and the technology is therefore not technically feasible for this engineering group.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous small, dispersed combustion units serving a variety of manufacturing operations throughout the facility. The relatively small size of many units, together with their varied configurations and operating schedules, makes installation of steam or water injection systems impractical. The additional piping, pumps, controls, and maintenance requirements would require source-specific engineering for each combustion unit and would not represent a practical retrofit strategy.

Representative Technology Determination

Steam or water injection was evaluated for each representative combustion-source engineering group. Because the process combustion equipment was not designed to accommodate combustion-zone fluid injection and implementation would require substantial modifications while potentially affecting combustion performance and product quality, the technology is not considered technically feasible for the grouped combustion sources evaluated in this study. Accordingly, steam or water injection is eliminated from further representative RACT consideration.

11.2.8 Dry Low-NOx Burners

Dry Low-NOx (DLN) burners reduce NOx emissions by controlling fuel-air mixing and combustion characteristics without the use of steam or water injection. This technology was developed primarily for combustion turbines and is commonly applied to utility and industrial gas turbine installations. The applicability of Dry Low-NOx burners was evaluated for each representative combustion-source engineering group to determine whether the technology represents a technically feasible RACT alternative for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units utilizing conventional industrial burner systems rather than combustion turbines. Dry Low-NOx burner technology is not designed for these combustion systems and cannot be practically retrofitted to the existing process equipment. Accordingly, Dry Low-NOx burners are not technically feasible for Group 1.

Group 2 – S-Plant

The combustion units within Group 2 consist primarily of heat-treat furnaces and aging ovens utilizing conventional industrial burner assemblies. Because these combustion systems are not combustion turbines and are not compatible with Dry Low-NOx burner technology, implementation is not technically feasible.

Group 3 – Building 120

Group 3 contains specialized process heating equipment employing conventional natural gas-fired burners designed to satisfy unique manufacturing requirements. Dry Low-NOx burner technology is not applicable to these combustion systems and therefore is not considered a technically feasible control alternative.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units located throughout the facility. These units likewise utilize conventional burner systems and are not compatible with combustion turbine Dry Low-NOx technology. Consequently, Dry Low-NOx burners are not technically feasible for Group 4.

Representative Technology Determination

Dry Low-NOx burners were evaluated for each representative combustion-source engineering group. Because the grouped emission units consist of conventional natural gas-fired process furnaces, ovens, and heaters rather than combustion turbines, Dry Low-NOx burner technology is not applicable to the combustion sources evaluated in this study. Accordingly, this technology is eliminated from further representative RACT consideration.

11.2.9 Ignition Timing Retard

Ignition timing retard reduces NOx emissions by delaying the combustion event within the combustion cycle, thereby reducing peak combustion temperatures and limiting thermal NOx formation. This control technology is applicable to spark-ignited internal combustion engines and is not generally employed on industrial furnaces, ovens, or other conventional process combustion equipment. The applicability of

ignition timing retard was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty combustion equipment utilizing conventional industrial burner systems. These combustion units do not employ spark-ignited reciprocating engines and therefore have no ignition timing system capable of adjustment. Accordingly, ignition timing retard is not technically feasible for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 are heat-treat furnaces and aging ovens utilizing conventional burner assemblies designed to provide controlled process heating. Because these units do not operate as reciprocating internal combustion engines, ignition timing retard is not applicable and cannot be implemented as a NO_x control strategy.

Group 3 – Building 120

Group 3 consists of specialized natural gas-fired process heating equipment utilizing conventional industrial combustion systems. The equipment does not incorporate adjustable ignition timing and therefore cannot utilize ignition timing retard as an emission control technology. Accordingly, this technology is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed natural gas-fired process furnaces and heating units located throughout the facility. Like the other representative engineering groups, these combustion sources utilize conventional burner systems rather than spark-ignited reciprocating engines. Consequently, ignition timing retard is not applicable and is not technically feasible for Group 4.

Representative Technology Determination

Ignition timing retard was evaluated for each representative combustion-source engineering group. Because the grouped emission units consist of conventional natural gas-fired process furnaces and heaters rather than spark-ignited internal combustion engines, the technology is not applicable to the combustion sources evaluated in this study. Accordingly, ignition timing retard is eliminated from further representative RACT consideration.

11.2.10 Separate Circuit After-Cooling

Separate circuit after-cooling reduces NO_x emissions by lowering the temperature of the combustion air supplied to internal combustion engines through the use of dedicated charge-air cooling systems. This technology is applicable primarily to turbocharged reciprocating internal combustion engines and is not generally employed on industrial furnaces, ovens, boilers, or other conventional process combustion equipment. The applicability of separate circuit after-cooling was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion equipment utilizing conventional burner systems. These combustion units do not employ turbocharged reciprocating engines or charge-air cooling systems. Accordingly, separate circuit after-cooling is not technically applicable or feasible for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist of heat-treat furnaces and aging ovens utilizing conventional industrial burners. Because these combustion systems do not incorporate engine intake air

or charge-air cooling equipment, separate circuit after-cooling cannot be implemented as a NO_x control technology. Therefore, this technology is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized natural gas-fired process heating equipment utilizing conventional furnace burner systems. The combustion equipment is not equipped with turbocharged engines or after-cooling systems, and retrofit of this technology is not compatible with the existing combustion design. Accordingly, separate circuit after-cooling is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units located throughout the facility. These units likewise utilize conventional industrial burner systems rather than turbocharged reciprocating engines. Consequently, separate circuit after-cooling is not applicable and is not technically feasible for Group 4.

Representative Technology Determination

Separate circuit after-cooling was evaluated for each representative combustion-source engineering group. Because the grouped emission units consist of conventional natural gas-fired furnaces, ovens, and process heaters rather than turbocharged reciprocating internal combustion engines, the technology is not applicable to the combustion sources evaluated in this study. Accordingly, separate circuit after-cooling is eliminated from further representative RACT consideration.

11.2.11 Fuel Emulsification

Fuel emulsification reduces NO_x emissions by introducing a controlled quantity of water into the fuel stream, thereby lowering peak flame temperatures during combustion and reducing thermal NO_x formation. This technology has been applied primarily to liquid fuel combustion systems and selected compression ignition engines and has limited application to natural gas-fired industrial combustion equipment. The applicability of fuel emulsification was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion equipment utilizing conventional natural gas burner systems. Because these combustion units operate exclusively on natural gas rather than liquid fuel, fuel emulsification cannot be practically implemented. Retrofitting the combustion systems to accommodate an emulsified fuel would require fundamental redesign of the fuel delivery and combustion systems without demonstrated applicability to the existing equipment. Accordingly, fuel emulsification is not technically feasible for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 utilize natural gas-fired burner systems designed to provide controlled metallurgical heating conditions. Fuel emulsification technology is not compatible with gaseous fuel combustion systems and would provide no practical means of reducing NO_x emissions for these units. Therefore, this technology is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 consists of specialized natural gas-fired process heating equipment utilizing conventional industrial gas burners. Because the combustion units do not utilize liquid fuel combustion systems, fuel emulsification is not applicable to the existing equipment and cannot be implemented as a representative NO_x control strategy.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed natural gas-fired process combustion units throughout the facility. Similar to the other representative engineering groups, these units utilize gaseous fuel combustion

systems and are not compatible with fuel emulsification technology. Consequently, fuel emulsification is not technically feasible for Group 4.

Representative Technology Determination

Fuel emulsification was evaluated for each representative combustion-source engineering group. Because the grouped emission units operate exclusively on natural gas and do not utilize liquid fuel combustion systems for which fuel emulsification was developed, the technology is not applicable to the combustion sources evaluated in this study. Accordingly, fuel emulsification is eliminated from further representative RACT consideration.

11.2.12 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) reduces NO_x emissions through controlled injection of ammonia or urea into the flue gas at elevated temperatures where the reagent reacts with nitrogen oxides to form nitrogen and water. Effective SNCR performance requires a relatively narrow furnace temperature window, adequate gas residence time, and sufficient mixing of the injected reagent with the flue gas. The applicability of SNCR was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible representative RACT alternative.

Group 1 – A-Plant

Group 1 consists of numerous independently operated process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units that vary considerably in size, firing rate, combustion chamber geometry, and operating temperature. These units generally do not provide the sustained furnace temperatures, residence times, or gas flow characteristics necessary to achieve effective SNCR performance. Installation would also require individual reagent injection systems, storage and handling equipment, controls integration, and source-specific engineering for each combustion unit. Accordingly, SNCR is not considered technically feasible as a representative common-control technology for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 are primarily heat-treat furnaces and aging ovens designed to maintain controlled metallurgical heating conditions. These units do not possess the furnace dimensions or operating characteristics necessary to establish the temperature window required for reliable SNCR operation. In addition, installation of reagent handling and injection systems on multiple independent process units would require extensive source-specific modifications. Therefore, SNCR is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 consists of specialized process heating equipment serving unique manufacturing operations. The relatively small combustion chambers, varying operating temperatures, and process-specific firing characteristics do not provide suitable conditions for effective reagent injection and NO_x reduction using SNCR technology. Consequently, SNCR is not considered technically feasible for this representative engineering group.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units distributed throughout multiple manufacturing buildings. The relatively small size of these units, together with their physical separation and diverse operating characteristics, precludes practical implementation of SNCR as a representative common-control technology. Individual reagent storage, injection equipment, and controls would be required for each combustion source, making the technology technically impractical for the engineering group.

Representative Technology Determination

Selective Non-Catalytic Reduction was evaluated for each representative combustion-source engineering group. The engineering evaluation determined that the grouped combustion sources do not provide the combustion chamber dimensions, flue gas temperature profiles, residence times, or operating characteristics necessary to support reliable SNCR performance. Implementation would also require extensive source-specific reagent handling and injection systems for numerous independent combustion units. Accordingly, SNCR is not identified as a technically feasible representative common-control RACT alternative for the grouped combustion sources evaluated in this study.

11.2.13 Nonselective Catalytic Reduction (NSCR)

Nonselective Catalytic Reduction (NSCR) reduces NO_x emissions by passing exhaust gases through a catalyst where nitrogen oxides, carbon monoxide, and hydrocarbons are simultaneously converted to nitrogen, carbon dioxide, and water. Effective NSCR operation requires tightly controlled rich-burn combustion conditions and is commonly applied to reciprocating internal combustion engines rather than industrial furnaces or process heating equipment. The applicability of NSCR was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units operating with conventional industrial burner systems. These combustion units operate under lean-burn conditions and do not produce exhaust gas compositions suitable for NSCR catalyst performance. Installation of catalyst reactors would also require significant modifications to individual exhaust systems without providing reliable NO_x control. Accordingly, NSCR is not technically feasible for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces and aging ovens utilizing conventional natural gas burner systems. These units are not designed to operate under the rich-burn conditions necessary for effective NSCR operation, and conversion to rich-burn combustion would adversely affect combustion efficiency, process temperature control, and product quality. Therefore, NSCR is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment designed for precise thermal processing. The combustion systems are incompatible with NSCR technology because they do not utilize reciprocating engines or rich-burn combustion systems. Retrofitting catalyst reactors and modifying combustion characteristics would require fundamental redesign of the existing equipment. Accordingly, NSCR is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units utilizing conventional lean-burn natural gas combustion systems. These combustion sources are incompatible with NSCR technology, and installation of individual catalyst systems would require extensive source-specific modifications without demonstrated technical applicability. Consequently, NSCR is not technically feasible for Group 4.

Representative Technology Determination

Nonselective Catalytic Reduction was evaluated for each representative combustion-source engineering group. Because the grouped emission units consist of lean-burn natural gas-fired process furnaces and heating equipment rather than rich-burn reciprocating internal combustion engines, the technology is not applicable to the combustion sources evaluated in this study. Accordingly, NSCR is eliminated from further representative RACT consideration.

11.2.14 Selective Catalytic Reduction (SCR) Using Urea, Ammonia, or Methane

Selective Catalytic Reduction (SCR) reduces NO_x emissions by injecting a reducing reagent, typically anhydrous ammonia, aqueous ammonia, or urea, into the flue gas upstream of a catalyst reactor where nitrogen oxides are converted to nitrogen and water. SCR is a proven post-combustion NO_x control technology for appropriately configured combustion systems. The applicability of SCR was evaluated for each representative combustion-source engineering group to determine whether it could be implemented as a representative common-control strategy for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of numerous independently operated process furnaces, heat-treat furnaces, reheat furnaces, die heaters, and specialty manufacturing combustion units distributed throughout Buildings 200, 206, and 210. Individual application of SCR to each combustion source would require separate catalyst reactors, reagent storage and distribution systems, induced draft fans, ductwork modifications, instrumentation, controls, and continuous catalyst maintenance. Alternatively, a centralized SCR system would require construction of an extensive common exhaust collection system to convey exhaust from numerous independent combustion units to a single catalyst reactor. Although technically feasible in principle, the representative engineering evaluation presented in Sections 8 through 10 demonstrates that the infrastructure required to implement centralized SCR is extensive and facility-wide in scope. Accordingly, SCR is technically feasible but is not considered a practical representative common-control strategy for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces, aging ovens, and associated process heating equipment located within Building 150. Similar to Group 1, implementation of SCR would require either installation of individual catalyst systems on each combustion unit or development of a common exhaust collection system serving multiple independent process units. Both approaches require substantial ductwork, structural modifications, reagent handling systems, controls integration, and ongoing catalyst management. Therefore, while technically feasible, SCR is not considered a practical representative common-control strategy for Group 2.

Group 3 – Building 120

Group 3 contains specialized process combustion equipment supporting unique manufacturing operations. The engineering evaluation determined that application of SCR would require extensive exhaust collection infrastructure, catalyst installation, reagent handling equipment, induced draft systems, and combustion system modifications that are disproportionate to the configuration of the representative combustion sources. Accordingly, SCR is technically feasible in principle but is not considered an appropriate representative common-control technology for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 consists primarily of numerous small, dispersed combustion units distributed throughout multiple manufacturing buildings. Because of the physical separation and relatively small size of these combustion sources, implementation of a centralized SCR system is not technically practical. Individual SCR installations would likewise require catalyst reactors, reagent systems, ductwork modifications, instrumentation, and controls for each combustion unit, resulting in an impractical retrofit configuration. Consequently, SCR is not considered a technically feasible representative common-control strategy for Group 4.

Representative Technology Determination

Selective Catalytic Reduction was evaluated for each representative combustion-source engineering group. Although SCR is a technically proven NO_x control technology, implementation for the representative combustion-source groups would require either numerous individual catalyst installations or extensive centralized exhaust collection infrastructure serving multiple independent combustion units. As demonstrated by the representative engineering and economic evaluations presented in Sections 8

through 10, the substantial infrastructure required for representative SCR implementation renders the technology impractical for the grouped combustion sources. Accordingly, SCR is not identified as a representative common-control RACT alternative for the combustion-source groups evaluated in this study. Source-specific application of SCR remains appropriate where warranted by the design, size, and operating characteristics of individual combustion sources.

11.2.15 Incineration (for Sources Other Than Boilers)

Incineration reduces emissions by thermally oxidizing combustible pollutants within a secondary combustion chamber. This technology is commonly applied to volatile organic compounds (VOC), hazardous air pollutants (HAP), and combustible process exhaust streams rather than nitrogen oxides generated during natural gas combustion. The applicability of incineration was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible NO_x control alternative for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units that generate NO_x as a product of fuel combustion. Incineration does not reduce combustion-generated NO_x emissions and would require installation of secondary combustion equipment that would consume additional fuel while potentially increasing NO_x formation. Accordingly, incineration is not technically feasible as a NO_x control technology for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 utilize natural gas-fired heating systems that do not generate combustible process exhaust streams requiring thermal oxidation. Installation of incineration equipment would not reduce NO_x emissions and would unnecessarily increase system complexity, fuel consumption, and operating costs. Therefore, incineration is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 consists of specialized process heating equipment utilizing conventional natural gas combustion. Because incineration is intended to destroy combustible organic compounds rather than control thermal NO_x formation, the technology is not applicable to the combustion sources within this engineering group.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed natural gas-fired process combustion units located throughout the facility. These units do not emit combustible exhaust streams that would benefit from thermal oxidation, and installation of individual incinerators would not provide NO_x reduction. Consequently, incineration is not technically feasible for Group 4.

Representative Technology Determination

Incineration was evaluated for each representative combustion-source engineering group. Because the grouped emission units generate NO_x through conventional natural gas combustion rather than through emission of combustible organic compounds, incineration does not represent an effective NO_x control technology. Installation of secondary combustion equipment would not reduce NO_x emissions and could increase overall fuel consumption and thermal NO_x formation. Accordingly, incineration is not identified as a technically feasible representative RACT alternative for the grouped combustion sources evaluated in this study.

11.2.16 Scrubbing (for Sources Other Than Boilers)

Scrubbing removes air pollutants by contacting the exhaust gas stream with a liquid absorbent or chemical reagent. Wet and dry scrubbers are commonly applied to control particulate matter, acid gases, sulfur dioxide, and selected hazardous air pollutants. Conventional scrubbing systems are generally ineffective for controlling thermal NO_x emissions generated by natural gas-fired combustion equipment

unless specifically designed as specialized chemical absorption systems, which are not representative of the combustion sources evaluated in this study. The applicability of scrubbing was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units that generate NO_x through high-temperature combustion. Conventional wet or dry scrubbers do not effectively remove combustion-generated NO_x from these exhaust streams and would require substantial exhaust ductwork, reagent handling systems, wastewater management, and corrosion-resistant materials of construction. Accordingly, scrubbing is not considered a technically feasible NO_x control technology for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 utilize conventional natural gas-fired heating systems that do not generate acid gases or particulate matter requiring scrubber control. Installation of scrubbers would not provide meaningful NO_x reduction while substantially increasing equipment complexity, water usage, wastewater generation, and maintenance requirements. Therefore, scrubbing is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment designed for controlled metallurgical operations. Conventional scrubbing systems are not intended to remove thermal NO_x from natural gas combustion exhaust and would require extensive modifications to each exhaust system without demonstrating effective NO_x control. Consequently, scrubbing is not considered technically feasible for this representative engineering group.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process combustion units located throughout the facility. Installation of individual scrubbing systems on each combustion source would require extensive exhaust modifications, liquid handling systems, wastewater collection, and ongoing maintenance while providing little or no reduction in combustion-generated NO_x emissions. Accordingly, scrubbing is not technically feasible for Group 4.

Representative Technology Determination

Scrubbing was evaluated for each representative combustion-source engineering group. Conventional wet and dry scrubber systems are designed primarily to control particulate matter, acid gases, and other soluble pollutants rather than thermal NO_x produced during natural gas combustion. Because scrubbing would not provide effective NO_x control for the representative combustion sources and would require substantial additional equipment, water usage, wastewater management, and maintenance, the technology is not identified as a technically feasible representative RACT alternative for the grouped combustion sources evaluated in this study.

11.2.17 Process Modification

Process modification reduces emissions by changing the manufacturing process, production methods, operating practices, or equipment configuration to reduce pollutant formation at the source. For combustion-related NO_x emissions, process modifications may include changes in production sequencing, heating cycles, process temperatures, throughput, or equipment utilization. The applicability of process modification was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing equipment supporting titanium and high-temperature alloy production. Process temperatures, heating rates, furnace residence times, and thermal cycles are established by product specifications and metallurgical requirements rather than by emission considerations. Modifying these process parameters would directly affect product quality, mechanical properties, and manufacturing capability. Accordingly, process modification is not considered a technically feasible NO_x control strategy for Group 1.

Group 2 – S-Plant

The combustion units within Group 2 support heat-treating and aging operations requiring precise thermal profiles to achieve specified metallurgical properties. Alteration of process temperatures, heating cycles, or production schedules would compromise product quality and customer specifications rather than reduce NO_x emissions through an emission control mechanism. Therefore, process modification is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment serving unique manufacturing operations. Furnace operating conditions are dictated by manufacturing requirements and product specifications, leaving little opportunity to modify the process for NO_x reduction without fundamentally altering the intended operation of the equipment. Consequently, process modification is not considered technically feasible for this engineering group.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed combustion units supporting a variety of manufacturing operations throughout the facility. Although operating schedules and equipment utilization may vary with production demand, the combustion processes themselves are integral to manufacturing. Reducing furnace operation by modifying production would represent process curtailment rather than implementation of an emission control technology. Accordingly, process modification is not technically feasible for Group 4.

Representative Technology Determination

Process modification was evaluated for each representative combustion-source engineering group. The operating conditions of the grouped combustion sources are established by manufacturing requirements, product specifications, and metallurgical process constraints rather than discretionary operating practices. Modifying these processes would fundamentally alter manufacturing operations or reduce production capacity rather than control NO_x emissions through an identifiable emission control technology. Accordingly, process modification is not identified as a technically feasible representative RACT alternative for the grouped combustion sources evaluated in this study.

11.2.18 Fuel Switching

Fuel switching reduces NO_x emissions by replacing a higher-emitting fuel with an alternative fuel having lower nitrogen content or more favorable combustion characteristics. Typical examples include conversion from coal or fuel oil to natural gas or other cleaner-burning gaseous fuels. The applicability of fuel switching was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative for the remaining natural gas-fired combustion sources.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units that already utilize natural gas as the primary combustion fuel. Natural gas is recognized as one of the lowest-NO_x conventional fossil fuels available for industrial combustion applications because of its negligible fuel-bound nitrogen content and favorable combustion characteristics. Since the combustion units already operate exclusively on natural gas, no practical

alternative fuel exists that would provide a meaningful reduction in NO_x emissions while maintaining equivalent process performance. Accordingly, fuel switching is not technically feasible for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 likewise operate exclusively on natural gas to support controlled heat-treating and aging operations. Conversion to another commercially available fuel would not provide a meaningful reduction in NO_x emissions and could adversely affect combustion performance, process temperature control, equipment reliability, and product quality. Therefore, fuel switching is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized natural gas-fired process heating equipment designed and optimized for gaseous fuel combustion. Because the existing combustion systems already utilize natural gas, no technically practical fuel substitution has been identified that would achieve additional NO_x reductions while maintaining equivalent manufacturing performance. Accordingly, fuel switching is not considered technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed natural gas-fired process combustion units throughout the facility. Similar to the other representative engineering groups, these combustion sources already utilize the lowest-NO_x conventional combustion fuel reasonably available for industrial process heating. Consequently, fuel switching would not provide additional meaningful NO_x reductions and is not technically feasible for Group 4.

Representative Technology Determination

Fuel switching was evaluated for each representative combustion-source engineering group. Because all grouped combustion sources already operate on natural gas, which represents the cleanest practical conventional fuel for these industrial combustion applications, no alternative fuel has been identified that would provide meaningful additional NO_x reductions while maintaining equivalent manufacturing capability. Accordingly, fuel switching is not identified as a technically feasible representative RACT alternative for the grouped combustion sources evaluated in this study.

11.2.19 Adjustment of Air/Fuel Ratio (Internal Combustion Engines Only)

Adjustment of the air-to-fuel ratio is a recognized NO_x control strategy for reciprocating internal combustion engines, where precise control of combustion stoichiometry can reduce peak combustion temperatures and nitrogen oxide formation. This technology is specifically intended for internal combustion engine applications and is not generally applicable to industrial process furnaces or other combustion equipment utilizing conventional burner systems. The applicability of air-to-fuel ratio adjustment was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units utilizing conventional industrial burner systems rather than reciprocating internal combustion engines. Although burner combustion systems inherently regulate fuel and combustion air, they do not utilize the engine air/fuel control strategies contemplated by this technology. Accordingly, adjustment of the air-to-fuel ratio for internal combustion engines is not technically applicable to Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 utilize conventional natural gas-fired burner systems designed to maintain controlled metallurgical heating conditions. These combustion systems are not reciprocating

internal combustion engines and therefore do not employ the engine air/fuel control methodologies associated with this technology. Accordingly, this control option is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment utilizing conventional industrial burners. Because these combustion units are not internal combustion engines, adjustment of the air-to-fuel ratio as contemplated by this control technology is not applicable. Existing burner adjustments are instead addressed through combustion tuning and Good Combustion Practices discussed elsewhere in this study.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 consists of numerous dispersed natural gas-fired process furnaces and heating units throughout the facility. Similar to the other representative engineering groups, these combustion sources utilize conventional burner systems and are not equipped with reciprocating internal combustion engines. Consequently, this technology is not technically applicable to Group 4.

Representative Technology Determination

Adjustment of the air-to-fuel ratio for internal combustion engines was evaluated for each representative combustion-source engineering group. Because the grouped emission units consist of conventional natural gas-fired furnaces, ovens, and process heaters rather than reciprocating internal combustion engines, this technology is not applicable to the combustion sources evaluated in this study. Optimization of combustion air for the existing burner systems is instead addressed through combustion tuning, Good Combustion Practices, oxygen trim optimization where applicable, and low excess air operation discussed elsewhere in this study. Accordingly, adjustment of the air-to-fuel ratio for internal combustion engines is eliminated from further representative RACT consideration.

11.2.20 Low Excess Air

Low excess air operation reduces thermal NO_x formation by minimizing the quantity of excess combustion air supplied to the burner while maintaining complete combustion, flame stability, acceptable carbon monoxide emissions, and safe furnace operation. Proper adjustment of excess air improves combustion efficiency and can provide incremental reductions in NO_x emissions when appropriately applied. The applicability of low excess air operation was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible representative RACT alternative.

Group 1 – A-Plant

Group 1 consists of numerous process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units having different burner designs, firing rates, process temperatures, and combustion control systems. Individual combustion units may benefit from optimization of excess air during normal combustion tuning; however, optimum excess air levels are source-specific and depend upon burner design, furnace loading, process requirements, combustion stability, and carbon monoxide formation. Accordingly, low excess air operation cannot be implemented as a single representative common-control strategy applicable across the engineering group.

Group 2 – S-Plant

The combustion sources within Group 2 support heat-treating and aging operations requiring controlled thermal conditions and stable combustion performance. Although excess air optimization may be incorporated into routine burner tuning for individual combustion units, the appropriate operating conditions vary among the furnaces and cannot be standardized across the representative group. Consequently, low excess air operation is not considered a representative common-control technology for Group 2.

Group 3 – Building 120

Group 3 consists of specialized natural gas-fired process heating equipment designed for unique manufacturing operations. Optimization of combustion air remains an equipment-specific operational practice performed during burner adjustment and maintenance. Because appropriate excess air settings vary by combustion unit and operating conditions, low excess air operation cannot be implemented as a representative engineering control applicable to the entire group.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed combustion units of varying size, age, burner configuration, and operating schedule. Excess air optimization is appropriately addressed during routine burner maintenance and combustion tuning for individual units but cannot be uniformly established across the representative engineering group. Therefore, low excess air operation is not considered a representative common-control strategy for Group 4.

Representative Technology Determination

Low excess air operation was evaluated for each representative combustion-source engineering group. The evaluation determined that optimization of excess air is an equipment-specific operational practice that should be incorporated into routine combustion tuning and Good Combustion Practices rather than implemented as a separate representative common-control technology. Appropriate excess air settings depend on the individual burner design, combustion characteristics, process requirements, and operating conditions of each combustion unit. Accordingly, low excess air operation is not identified as a representative common-control RACT alternative for the grouped combustion sources evaluated in this study. Source-specific optimization of excess air remains an appropriate operational measure and is included as a component of the proposed RACT strategy for Boilers B008 and B009.

11.2.21 Mid-Kiln Firing

Mid-kiln firing is a combustion modification technique developed specifically for long dry and long wet Portland cement kilns. The technology reduces NO_x emissions by introducing fuel at an intermediate location within the rotary kiln to create staged combustion conditions that suppress thermal NO_x formation. Because the effectiveness of mid-kiln firing depends upon the unique geometry, material flow, and combustion characteristics of rotary cement kilns, the applicability of this technology was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion equipment. These combustion units are not rotary cement kilns and do not possess the combustion geometry, process configuration, or material flow characteristics necessary to implement mid-kiln firing. Accordingly, this technology is not technically applicable to Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces and aging ovens designed to achieve controlled metallurgical heating conditions. These units do not utilize rotary kiln combustion and cannot accommodate fuel injection at an intermediate combustion zone. Therefore, mid-kiln firing is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment utilizing conventional industrial burner systems. Because the combustion units are not cement kilns and do not employ rotary kiln operation, the engineering principles underlying mid-kiln firing are not applicable. Consequently, this technology is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units located throughout the facility. None of these combustion sources operate as rotary cement kilns or possess the physical configuration necessary to support staged fuel injection associated with mid-kiln firing. Accordingly, the technology is not technically feasible for Group 4.

Representative Technology Determination

Mid-kiln firing was evaluated for each representative combustion-source engineering group. The grouped emission units consist of conventional natural gas-fired furnaces, ovens, and process heaters rather than rotary Portland cement kilns for which this technology was developed. Because the required combustion geometry, material flow, and process configuration do not exist at the facility, mid-kiln firing is not applicable to the combustion sources evaluated in this study and is eliminated from further representative RACT consideration.

11.2.22 Mid-Kiln Air Injection

Mid-kiln air injection is a combustion modification technology developed for long rotary Portland cement kilns. The technology reduces NO_x emissions by introducing combustion air at intermediate locations within the kiln to establish staged combustion conditions that suppress thermal NO_x formation. Effective application requires the unique geometry, combustion characteristics, and material flow associated with rotary cement kilns. The applicability of mid-kiln air injection was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of natural gas-fired process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion equipment utilizing conventional industrial burner systems. These combustion units do not possess the rotary kiln configuration, extended combustion zone, or process characteristics necessary for mid-kiln air injection. Accordingly, this technology is not technically applicable to Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces and aging ovens designed to maintain controlled metallurgical heating conditions. These units do not employ rotary kiln combustion and cannot accommodate intermediate combustion air injection as contemplated by this technology. Therefore, mid-kiln air injection is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment utilizing conventional natural gas-fired burners. Because the combustion equipment is not configured as rotary cement kilns, the engineering principles underlying mid-kiln air injection are not applicable. Consequently, this technology is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units serving a variety of manufacturing operations throughout the facility. None of these combustion sources possess the combustion geometry or operating characteristics necessary to implement staged mid-kiln air injection. Accordingly, this technology is not technically feasible for Group 4.

Representative Technology Determination

Mid-kiln air injection was evaluated for each representative combustion-source engineering group. Because the grouped emission units consist of conventional natural gas-fired furnaces, ovens, and process heaters rather than rotary Portland cement kilns, the technology is not applicable to the combustion sources evaluated in this study. The required kiln geometry, combustion characteristics, and

material handling configuration necessary for successful implementation do not exist at the facility. Accordingly, mid-kiln air injection is eliminated from further representative RACT consideration.

11.2.23 Gaseous Fuels Reburn

Gaseous fuels reburn is a combustion staging technology that reduces NO_x emissions by injecting natural gas or another gaseous fuel downstream of the primary combustion zone to create a fuel-rich reburn zone where nitrogen oxides are chemically reduced to nitrogen. Effective implementation requires a sufficiently large furnace volume, appropriate gas temperatures, adequate residence time, and downstream overfire air to complete combustion. The applicability of gaseous fuels reburn was evaluated for each representative combustion-source engineering group to determine whether it represents a technically feasible RACT alternative.

Group 1 – A-Plant

Group 1 consists of numerous independently operated process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units having different combustion chamber geometries, firing rates, and process temperature requirements. These combustion systems generally lack the furnace dimensions, residence time, and combustion zone separation necessary to establish effective reburn and burnout zones. Implementation would require extensive reconstruction of individual furnaces, installation of secondary fuel injection systems, overfire air systems, combustion controls, and source-specific performance optimization. Accordingly, gaseous fuels reburn is not considered technically feasible as a representative common-control strategy for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces and aging ovens designed to provide precise thermal conditions necessary for metallurgical processing. These combustion units do not possess the combustion chamber dimensions or operating characteristics necessary to support staged reburn combustion. Modification of the existing furnace designs would substantially alter combustion performance and could adversely affect product quality. Therefore, gaseous fuels reburn is not technically feasible for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment serving unique manufacturing operations. The relatively compact combustion chambers and process-specific operating conditions do not provide adequate residence time or combustion zone separation necessary for effective gaseous fuels reburn. Implementation would require fundamental redesign of the combustion systems rather than a practical retrofit. Accordingly, this technology is not technically feasible for Group 3.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 includes numerous dispersed process furnaces and small combustion units distributed throughout the facility. The relatively small size of these combustion sources, combined with their physical separation and diverse operating characteristics, precludes practical implementation of gaseous fuels reburn. Individual retrofits would require secondary fuel systems, combustion modifications, controls integration, and extensive engineering for each combustion unit, making the technology impractical for the representative engineering group.

Representative Technology Determination

Gaseous fuels reburn was evaluated for each representative combustion-source engineering group. The engineering evaluation determined that the grouped combustion sources do not possess the furnace size, combustion chamber geometry, residence time, or combustion zone configuration necessary to support effective reburn technology. Implementation would require substantial reconstruction of individual combustion systems together with secondary fuel injection equipment, overfire air systems, and advanced combustion controls. Accordingly, gaseous fuels reburn is not identified as a technically

feasible representative common-control RACT alternative for the grouped combustion sources evaluated in this study.

11.2.24 Other RACT Alternatives

OAC 3745-110-03(J)(1)(h) recognizes that NO_x control technologies continue to evolve and allows consideration of other technically demonstrated control alternatives not specifically identified within the rule. Accordingly, a review was performed to determine whether any additional commercially demonstrated combustion modifications, post-combustion control technologies, or operational practices beyond those previously evaluated would represent technically feasible representative RACT alternatives for the grouped natural gas-fired combustion sources at the Howmet Aerospace Cleveland facility.

Group 1 – A-Plant

Group 1 consists of numerous independently operated process furnaces, reheat furnaces, heat-treat furnaces, die heaters, and specialty manufacturing combustion units serving diverse production operations. No additional commercially demonstrated NO_x control technologies were identified that could be broadly applied across the representative engineering group without requiring substantial source-specific engineering, combustion system redesign, or modification of established manufacturing processes. Accordingly, no additional representative RACT technologies were identified for Group 1.

Group 2 – S-Plant

The combustion sources within Group 2 consist primarily of heat-treat furnaces and aging ovens designed to achieve controlled metallurgical heating conditions. A review of commercially available combustion and post-combustion NO_x control technologies identified no additional technologies beyond those previously evaluated that could be implemented as representative common-control measures while maintaining required process performance. Therefore, no additional representative RACT technologies were identified for Group 2.

Group 3 – Building 120

Group 3 contains specialized process heating equipment supporting unique manufacturing operations. Available combustion and emission control technologies were reviewed to determine whether additional technically demonstrated NO_x control alternatives existed beyond those previously discussed. No additional technologies applicable to the representative engineering group were identified.

Group 4 – H-Plant and Remaining Small Combustion Sources

Group 4 consists of numerous dispersed process combustion units located throughout multiple manufacturing buildings. Because of the diversity, physical separation, and relatively small size of these combustion sources, no additional commercially demonstrated NO_x control technologies were identified that could reasonably be implemented as representative common-control strategies for the engineering group.

Representative Technology Determination

A review of other commercially demonstrated NO_x control technologies and operational practices was completed for each representative combustion-source engineering group. No additional technologies beyond those evaluated in Sections 11.2.1 through 11.2.23 were identified that are technically applicable to the grouped combustion sources or that would provide a representative common-control RACT alternative. Accordingly, the technologies evaluated in this section represent the complete review of technically feasible NO_x control alternatives considered for the representative combustion-source groups in accordance with OAC 3745-110-03(J)(1)(h).

12. Implementation Considerations

Implementation of the proposed RACT determination developed in this study consists primarily of installation of Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR), together with associated combustion controls and balance-of-system modifications, for Boilers B008 and B009. As discussed throughout Sections 6 through 11, the engineering evaluation concluded that LNB/ULNB with integrated FGR represents the most appropriate combustion-side NO_x control technology for the subject boilers and constitutes the proposed source-specific RACT. Implementation of this technology will require detailed engineering design, procurement of replacement burner assemblies and associated equipment, combustion system integration, permitting, installation during scheduled maintenance outages, startup, commissioning, combustion tuning, and post-installation performance verification.

The selected retrofit extends beyond replacement of the burner assemblies and includes installation of induced flue gas recirculation equipment, modifications to the forced draft fan systems, combustion air ductwork, fuel train integration, burner management controls, instrumentation, electrical integration, and associated boiler front wall modifications as required by the selected equipment manufacturer. Because the boilers provide steam necessary for normal manufacturing operations, implementation must be carefully coordinated with planned facility outages to minimize impacts on production while maintaining safe and reliable boiler operation. Following installation, the combustion systems will undergo startup, controls optimization, combustion tuning, and performance verification to demonstrate compliance with the final Ohio EPA RACT determination.

For the remaining natural gas-fired combustion sources evaluated under the representative engineering group methodology, no additional representative common-control technologies were identified as technically feasible and economically reasonable RACT alternatives. Accordingly, no implementation activities beyond continued operation, routine maintenance, and existing operational practices are proposed for the representative combustion-source groups evaluated in this study.

12.1 Proposed RACT Implementation Schedule

Table 12-1 presents a representative implementation schedule beginning with issuance of the final Ohio EPA RACT determination. The schedule reflects the anticipated sequence of permitting, detailed engineering, equipment procurement, fabrication, installation, startup, commissioning, and performance verification activities necessary to implement the selected LNB/ULNB with integrated FGR retrofit for Boilers B008 and B009.

Pursuant to OAC 3745-110-04(B)(1), Howmet Aerospace will implement the approved RACT controls as expeditiously as practicable, but not later than two years following the effective date of the final RACT determination. Consistent with normal facility operations, major retrofit activities are scheduled during the two planned summer outage periods to minimize impacts on steam production and manufacturing operations while allowing sufficient time for installation, startup, combustion tuning, and performance verification.

Table 12-1. Proposed RACT Implementation Schedule

Milestone	Completion Date	Cumulative Time from Ohio EPA Approval
Final Ohio EPA RACT Approval	8/1/2026	0
Field Engineering	8/1/2026 – 1/1/2027	153
PTI Application/Issuance	1/28/2027	180
Equipment fabrication and delivery	2/1/2027 – 8/1/2027	365
Outage #1	9/1/2027 – 11/30/2027	486
Start-up	11/30-2027 – 12/30/2027	516
Outage #2	4/1/2028 – 6/30/2028	699
Start-up	7/1/2028 – 7/31/2028	730

13. Engineering Limitations and Future Considerations

The evaluations and conclusions presented in this study are based on available operating information, recent emissions testing data, study-level engineering assumptions, publicly available technical information, prior facility-specific evaluations, and engineering judgment applicable to existing natural gas-fired package boilers. As with any source-specific retrofit evaluation, additional engineering review and vendor-specific evaluation may be appropriate prior to final design, procurement, or implementation of major physical control technologies.

Potential future refinement items may include the following:

- Additional stack testing or operational data collection if requested by Ohio EPA or if future operating conditions materially change.
- Vendor-specific engineering evaluation if additional combustion retrofit controls are required by a final agency determination.
- Preparation of detailed design documents, procurement specifications, and implementation planning if future retrofit controls are selected.
- Revision of this engineering evaluation if facility operations, fuel usage, emission characteristics, or applicable regulatory requirements materially change.

14. References

1. Ohio Administrative Code (OAC) Chapter 3745-110, "Nitrogen Oxides — Reasonably Available Control Technology."
2. Trinity Consultants, "Top-Down NO_x RACT Analysis for U. S. Steel Lorain Tubular Operations," prepared for United States Steel Corporation, January 2024.
3. U.S. Environmental Protection Agency, Air Pollution Control Cost Manual, Sixth Edition, EPA-452/B-02-001 and subsequent updates.
4. U.S. Environmental Protection Agency, Alternative Control Techniques (ACT) Documents and NO_x Control Technology Guidance applicable to Industrial Boilers and Combustion Sources.
5. Prior facility-specific RACT evaluations and engineering information for Boilers B008 and B009, including historical combustion retrofit evaluations and burner-system assessments.
6. April 2026 boiler stack test reports and associated operating data for Boilers B008 and B009.
7. Available facility operating information, fuel usage records, emissions calculations, and boiler operating data provided by Howmet Aerospace.
8. Historical engineering retrofit evaluation (2011 basis) with updated study-level cost escalation.
9. Rule Package: OAC Chapter 3745-110 Response to Comments, July 7, 2021

15. Summary

This study presents a source-specific top-down NO_x Reasonably Available Control Technology (RACT) evaluation for Boilers B008 and B009 together with a representative engineering evaluation of the remaining natural gas-fired combustion sources at the Howmet Aerospace Cleveland facility in accordance with Ohio Administrative Code (OAC) Chapter 3745-110. The evaluation included review of applicable combustion modification technologies, post-combustion control technologies, representative engineering feasibility, vendor information, representative cost-effectiveness analyses, and current facility operating conditions.

For Boilers B008 and B009, the engineering evaluation identified Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR) and associated combustion controls as the most appropriate source-specific RACT technology. The evaluation included review of a vendor proposal incorporating replacement burner assemblies, induced flue gas recirculation, combustion controls, forced draft fan modifications, burner management upgrades, and associated boiler modifications. The representative cost-effectiveness analysis demonstrated that this technology is economically reasonable for the subject boilers and provides the greatest practical combustion-side NO_x reduction without requiring installation of post-combustion catalytic controls.

Implementation of the selected RACT will require replacement of the existing burner systems together with installation of integrated FGR, combustion controls, associated balance-of-system modifications, startup, commissioning, and performance optimization. Detailed engineering design, procurement, installation scheduling, and permitting activities will be completed following Ohio EPA approval of the final RACT determination. Consistent with OAC 3745-110-04(B)(1), the selected RACT controls will be implemented as expeditiously as practicable and no later than two years following the final RACT determination. A representative implementation schedule is presented in Section 12 of this study.

Recent stack testing performed during April 2026 measured baseline NO_x emission rates of approximately 0.125 lb/MMBtu for Boiler B008 and approximately 0.149 lb/MMBtu for Boiler B009 under representative operating conditions. These measured emission rates served as the basis for the representative engineering and economic evaluations completed in this study. Vendor information indicates that the proposed LNB/ULNB with integrated FGR system is capable of achieving substantially lower NO_x emission rates under specified operating conditions, subject to final detailed engineering, equipment selection, startup, combustion tuning, and post-installation performance verification.

The study also evaluated the remaining natural gas-fired combustion sources using the representative engineering group methodology established in Section 1. Four representative engineering groups encompassing forty-two combustion emission units were evaluated against each of the control technologies identified in OAC 3745-110-03(J)(1)(h). The engineering evaluation concluded that no representative common-control technology, including centralized combustion modification or post-combustion control systems, represents a technically feasible and economically reasonable RACT alternative for the grouped combustion sources. The diversity of furnace configurations, manufacturing processes, operating characteristics, equipment locations, and combustion system designs precludes implementation of a representative common-control retrofit applicable across the engineering groups.

Accordingly, Howmet Aerospace proposes that source-specific RACT for Boilers B008 and B009 consist of installation of Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR), associated combustion controls, continued firing of natural gas, implementation of Good Combustion Practices, annual combustion tune-ups, optimization of combustion system performance, and compliance with the applicable source-specific NO_x emission limitations established through the Ohio

EPA RACT determination. For the remaining grouped combustion sources, the representative engineering evaluations demonstrate that no additional common-control NO_x technology constitutes RACT under the representative engineering methodology presented in this study.

Appendix A. Calculation Notes

Key equations and engineering assumptions used in this study are summarized below. These calculations are intended to support comparative emissions evaluation, heat input estimation, and cost-effectiveness calculations associated with the source-specific NO_x RACT analysis for Boilers B008 and B009.

Appendix Table A-1. Calculation Bases and Notes

Calculation	Formula / Assumption
Annual NO _x emissions from annual heat input	$\text{NO}_x \text{ TPY} = \text{Annual Heat Input (MMBtu/year)} \times \text{Emission Factor (lb/MMBtu)} \div 2,000 \text{ lb/ton}$
Annual heat input derived from annual NO _x emissions	$\text{Annual Heat Input (MMBtu/year)} = \text{NO}_x \text{ TPY} \times 2,000 \div \text{Emission Factor (lb/MMBtu)}$
Annual NO _x reduction from assumed control efficiency	$\text{Annual NO}_x \text{ Reduction (TPY)} = \text{Baseline NO}_x \text{ Emissions} \times \text{Assumed Control Reduction Efficiency}$
Cost effectiveness	$\text{Cost Effectiveness (\$/ton removed)} = \text{Annualized Cost} \div \text{Annual NO}_x \text{ Reduction}$
Controlled emission rate estimate	$\text{Controlled NO}_x \text{ Rate (lb/MMBtu)} = \text{Baseline Emission Rate} \times (1 - \text{Assumed Control Reduction Efficiency})$
Natural gas heat input conversion	1 standard cubic foot natural gas = 1,020 Btu/scf (HHV assumed)
Natural gas meter conversion	1 CCF natural gas = approximately 0.102 MMBtu
Capital recovery factor (CRF)	7 percent interest rate; 10-year project life; $\text{CRF} \approx 0.1424$
Study-level cost basis	Costs developed using study-level engineering estimates, available retrofit information, engineering judgment, and publicly available cost methodology concepts

Appendix B. Detailed Study-Level Cost Worksheets

The following worksheets provide the detailed CAPEX and annual cost structure behind the summary cost-effectiveness tables. Values are study-level planning estimates prepared without current vendor pricing. These study-level estimates should be refined or confirmed through vendor/OEM quotations and detailed engineering review prior to final design, procurement, or implementation of major physical retrofit controls.

Natural gas usage recorded during the April 2026 stack testing was reported in hundred cubic feet (CCF). Heat input was calculated using an assumed higher heating value (HHV) of 1,020 Btu per standard cubic foot (scf), consistent with EPA standard assumptions and industry practice. On this basis, 1 CCF is equivalent to approximately 0.102 MMBtu.

Calculated heat input per test run ranged from approximately 85 to 86 MMBtu for Boiler B008 and 84 to 85 MMBtu for Boiler B009. These values are consistent with operation at approximately 90 percent of the 98.8 MMBtu/hr rated capacity and confirm that stack testing was conducted under representative near-high-load conditions.

Appendix Table B-1. Stack Test Run Fuel Use and Calculated Heat Input per Boiler

Boiler	Run	Natural Gas Use (CCF)	Calculated Heat Input (MMBtu)
B008	Run 1	838	85.48
B008	Run 2	836	85.27
B008	Run 3	847	86.39
B008	Average	840.3	85.71
B009	Run 1	827	84.35
B009	Run 2	838	85.48
B009	Run 3	838	85.48
B009	Average	834.3	85.10

Note: Heat input calculated using 1020 Btu/scf (HHV), where 1 CCF = 0.102 MMBtu.

Appendix Table B-2. Combustion Tune-up / Burner Optimization Cost Worksheet per Boiler

Cost element	Initial Cost	Annual cost	Notes
Initial field review and setup documentation	\$12,000	—	Initial field review and setup documentation.
Initial tune and annual retune	\$18,000	\$12,000	Initial tune and annual retune.
Initial and annual verification testing support	\$7,000	\$3,000	Initial and annual verification testing support.
Procedures, checklist, and training updates	\$3,000	\$1,000	Procedures, checklist, and training updates.
Study-level allowance	\$5,000	\$2,000	Study-level allowance.
Total	\$45,000	\$18,000	Representative study-level estimate for combustion optimization program implementation.

Appendix Table B-3. Oxygen Trim / Combustion Control Modernization Cost Worksheet per Boiler

Cost element	Initial Cost	Annual cost	Notes
Analyzer probe, sample conditioning, calibration gases	\$45,000	\$8,000	Analyzer probe, sample conditioning, calibration gases.
Controls and mechanical trim items	\$20,000	\$6,000	Minor mechanical trim items and combustion-controls support.
PLC/DCS integration and programming	\$40,000	\$6,000	Controls integration and programming.
Installation, checkout, and commissioning	\$55,000	\$9,000	Field installation, checkout, and commissioning support.
Testing, training, and contingency allowance	\$20,000	\$6,000	Operator training, testing, and contingency allowance.
Total	\$180,000	\$35,000	Representative screening-level estimate for controls modernization and combustion optimization support.

Appendix Table B-4. Low Excess Air Optimization Cost Worksheet per Boiler

Cost element	Initial Cost	Annual cost	Notes
Combustion tuning and instrumentation review	\$25,000	\$5,000	Combustion tuning and instrumentation review.
Controls adjustments and burner settings	\$35,000	\$7,000	Controls adjustments and burner settings support.
Verification testing	\$15,000	\$5,000	Periodic verification testing and operational review.
Procedures and operator support	\$5,000	\$2,000	Procedures and operator support.
Study-level contingency	\$10,000	\$3,000	Study-level contingency allowance.
Total	\$90,000	\$22,000	Representative screening-level estimate for low excess air optimization implementation.

Appendix Table B-5. FGR Retrofit / Fan and Duct Modification Cost Worksheet per Boiler

Cost element	Initial Cost	Annual cost	Notes
Fan margin, duct routing, stack takeoff, controls integration review	\$65,000	—	Fan margin, duct routing, stack takeoff, controls integration review.
Fan upgrade allowance	\$190,000	\$18,000	Required to accommodate additional FGR flow, pressure drop, and combustion-system integration.
Ductwork and installation allowance	\$240,000	\$26,000	Duct routing and mechanical installation allowance.
Controls, interlocks, tuning, startup support	\$90,000	\$18,000	Combustion controls, interlocks, tuning, and startup support.
Study-level retrofit uncertainty allowance	\$65,000	\$8,000	Study-level retrofit uncertainty allowance.
Total	\$650,000	\$70,000	Representative screening-level estimate for FGR retrofit / fan and duct modifications.

Appendix Table B-6. LNB/ULNB + Induced FGR + Controls Cost Worksheet per Boiler

Cost Element	Initial Cost	Annual Cost	Notes
2026 vendor proposal base scope	\$997,619	—	Vendor proposal base scope for low-NOx burner replacement, induced FGR integration, and combustion-controls modernization.
Owner-side integration / excluded-scope allowance	\$75,000	—	Allowance for owner-side integration, electrical coordination, controls integration, and excluded-scope implementation support.
Escalation, engineering, and contingency round-up	\$77,381	—	Representative escalation, engineering support, commissioning, and contingency allowance for retrofit implementation.
Annual burner/FGR tuning and verification support	—	\$20,000	Annual burner/FGR tuning and verification support.
Controls/VFD/FGR system maintenance support	—	\$20,000	Controls, VFD, and FGR system maintenance support.
Annual contingency / operator support allowance	—	\$15,000	Annual contingency and operator support allowance.
Total	\$1,150,000	\$55,000	Representative screening-level retrofit estimate for LNB/ULNB with induced FGR and combustion controls modernization.

Appendix Table B-7. SNCR Cost Worksheet per Boiler

Cost element	Initial Cost	Annual cost	Notes
Total Capital Investment (TCI) from EPA SNCR workbook	\$2,521,620	—	Total capital investment from completed EPA SNCR cost workbook using 2026 inputs and study-level design assumptions.
Direct Annual Cost (DAC) from EPA SNCR workbook	—	\$45,662	Direct annual cost from completed EPA SNCR workbook. Includes annual maintenance, reagent, electricity, water, fuel, and related direct annual cost categories.
Indirect Annual Cost (IDAC) from EPA SNCR workbook	—	\$239,176	Indirect annual costs from completed EPA SNCR workbook, including capital recovery and administrative charges.
Total Annual Cost (TAC) cross-check	—	\$284,838	TAC = DAC + IDAC. This value is used as the Study Annualized Cost in the comparative RACT tables.
Reference Total - SNCR EPA workbook outputs	\$2,521,620	\$284,838	Single-boiler screening estimate derived directly from completed EPA SNCR workbook outputs.

Appendix Table B-8.SCR Cost Worksheet per Boiler

Cost element	Initial Cost	Annual cost	Notes
Total Capital Investment (TCI) from EPA SCR workbook	\$5,593,742	—	Total capital investment from completed EPA SCR cost workbook using 2026 inputs and study-level design assumptions.
Direct Annual Cost (DAC) from EPA SCR workbook	—	\$52,789	Direct annual cost from completed EPA SCR workbook. Includes maintenance, reagent, electricity, catalyst replacement, and related direct annual cost categories.
Indirect Annual Cost (IDAC) from EPA SCR workbook	—	\$453,189	Indirect annual costs from completed EPA SCR workbook, including capital recovery and administrative charges.
Total Annual Cost (TAC) cross-check	—	\$505,978	TAC = DAC + IDAC. This value is used as the Study Annualized Cost in the comparative RACT tables.
Reference Total - SCR EPA workbook outputs	\$5,593,742	\$505,978	Single-boiler screening estimate derived directly from completed EPA SCR workbook outputs.

Appendix B values represent comparative screening-level engineering and economic estimates developed solely for source-specific RACT evaluation purposes. These estimates are intended to support relative control option comparisons and are not intended to represent final engineered construction costs, vendor quotations, guaranteed pricing, detailed design studies, or enforceable permit limitations. Actual project costs and operational impacts may vary substantially depending on site-specific retrofit conditions, equipment configuration, labor market conditions, outage requirements, reagent usage, financing assumptions, inflation, and vendor-specific design considerations. Annualized costs are dependent upon the economic assumptions incorporated into the referenced EPA cost methodologies and study-level engineering assumptions

Appendix C. Technical Feasibility Elimination Detail

The following detailed technical screening rationale is provided to support the administrative record associated with the source-specific RACT evaluation. Supporting engineering documentation, vendor information, and facility-specific operating information were considered where available.

Appendix Table C-1. Detailed Technical Screening Rationale for Controls Eliminated or Retained Only Conditionally

Technology	Detailed rationale	Final screening position
Overfire air / separated overfire ports	Overfire air is principally applicable to larger furnace geometries where staged combustion zones can be created. The existing boiler and burner configuration does not provide sufficient furnace geometry or combustion staging volume to support effective overfire air retrofit implementation.	Eliminate
Burners out of service (BOOS)	BOOS is a load-dispatch technique for multiple-burner units. The subject boilers are configured as single-burner package boilers, and BOOS is not compatible with the existing combustion design and steam production requirements.	Eliminate
Steam/water injection	Steam or water injection is more commonly associated with turbines or specialized combustion systems and would adversely affect boiler efficiency, combustion stability, and equipment reliability.	Eliminate
Fuel emulsification	Fuel emulsification is associated with liquid fuel combustion systems and is not applicable to natural gas-fired package boilers.	Eliminate
Dry low-NOx burners	Dry low-NOx burner terminology is generally associated with combustion turbine applications rather than natural gas-fired package boilers. Modern ULNB technology is separately evaluated under the LNB/ULNB category.	Eliminate as separate category
NSCR	Nonselective catalytic reduction is associated with rich-burn engines and is not technically appropriate for lean natural gas-fired boiler exhaust streams.	Eliminate
Incineration / scrubbing	These technologies are not recognized NOx RACT approaches for natural gas-fired package boilers and do not directly address thermal NOx formation mechanisms.	Eliminate
SNCR	SNCR may be applicable to certain industrial combustion sources; however, effective operation requires a narrowly defined furnace temperature window, adequate residence time, and sufficient reagent mixing conditions. Available information for the subject package boilers does not demonstrate suitable and maintainable combustion conditions necessary to support reliable SNCR retrofit operation under representative operating conditions. In addition, prior facility-specific evaluations did not identify SNCR as a feasible retrofit option for these units.	Not technically feasible based on temperature limitations; retained only for completeness of RACT record
SCR	SCR feasibility depends not only on catalyst chemistry, but also on available space, duct routing, pressure drop impacts, catalyst operating temperature, reagent handling requirements, constructability, and operational reliability considerations. SCR is retained for economic screening because it represents the highest demonstrated NOx removal technology.	Retain for cost screen; not selected as RACT in draft

Appendix D. Sensitivity Analysis

The following sensitivity analysis illustrates how control cost effectiveness varies depending on the assumed baseline operating conditions and annual NOx emissions profile for Boilers B008 and B009. This comparison is important because historical evaluations of combustion retrofit technologies were based on substantially higher assumed annual utilization than current actual operating conditions reflected in recent fuel usage and emissions data.

The sensitivity cases below compare representative actual operating conditions, historical higher-utilization scenarios, and theoretical potential-to-emit (PTE) operating assumptions. The analysis demonstrates that cost effectiveness for major physical retrofit controls is strongly influenced by the annual NOx mass available for reduction.

Appendix Table D-1. Sensitivity of NOx Control Cost Effectiveness to Baseline Operating Assumptions

Scenario	Combined B008+B009 Baseline NOx (TPY)	LNB/ULNB + IFGR Tons Removed Assuming 0.15 to 0.08 lb/MMBtu	LNB/ULNB + IFGR Annualized Cost	LNB/ULNB + IFGR Cost Effectiveness (\$/ton removed)	SCR Tons Removed at 85%	SCR Annualized Cost	SCR Cost Effectiveness (\$/ton removed)	Interpretation
2025 actual combined operating basis	21.62	10.1	\$163,300	\$16,174	18.38	\$505,978	\$27,533	Cost effectiveness is high because current actual annual NOx mass is relatively low compared with the capital-intensive retrofit scope.
Combined PTE / theoretical maximum utilization basis	129.82	60.63	\$163,300	\$2,694	110.35	\$505,978	\$4,585	Cost effectiveness improves substantially when evaluated against full theoretical utilization and higher annual NOx mass.

Note Values presented in this appendix are representative screening-level sensitivity calculations based on combined operating assumptions for Boilers B008 and B009. Cost-effectiveness values are derived directly from the Appendix D workbook screening calculations and are intended solely for comparative RACT evaluation purposes. Annualized costs shown for LNB/ULNB + IFGR and SCR reflect representative study-level screening estimates and are not intended to represent final engineered project costs, procurement quotations, or enforceable permit limitations.

Attachment 1
SCR EPA Cost Manual Workbook
And
SNCR EPA Cost Manual Workbook

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates ($\pm 30\%$) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Natural Gas ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.25

* NOTE: You must document why a retrofit factor of 1.25 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

12.05 MW

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual MWhs output?

16,500 MWhs

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

700 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable ▼

Enter the sulfur content (%S) =

percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☐ Method 1
☐ Method 2
☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

222 days

Number of days the boiler operates (t_{plant})

222 days

Number of SCR reactor chambers (n_{SCR})

1

Number of catalyst layers (R_{layer})

3

Inlet NO_x Emissions (NO_{x,in}) to SCR

0.15 lb/MMBtu

Outlet NO_x Emissions (NO_{x,out}) from SCR

0.0225 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers (Vol_{catalyst})

(Enter "UNK" if value is not known)

UNK Cubic feet

Flue gas flow rate (Q_{fluegas})

(Enter "UNK" if value is not known)

UNK acfm

Estimated operating life of the catalyst (H_{catalyst})

24,000 hours

Estimated SCR equipment life

30 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)

400 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})

29 percent*

Density of reagent as stored (ρ_{stored})

56 lb/cubic feet*

Number of days reagent is stored (t_{storage})

14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution

71 lbs/ft³

29.4% aqueous NH₃

56 lbs/ft³

Select the reagent used

Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year

2026

CEPCI for 2026

850 Enter the CEPCI value for 2026

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

7 Percent

Reagent (Cost_{reag})

0.293 \$/gallon for 29% ammonia*

* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

Electricity (Cost_{elect})

0.0850 \$/kWh

Catalyst cost (CC_{replace})

\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)

* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate

75.00 \$/hour (including benefits)

Operator Hours/Day

4.00 hours/day*

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.005

Administrative Charges Factor (ACF) =

0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	$Bmw \times NPHR =$	98.8	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	105,558	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		16,500	MWhs
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.82	
Total System Capacity Factor (CF_{total}) =	$(Boutput/Bmw) \times (t_{scr}/t_{plant}) =$	0.156	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	1369	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	85.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	12.60	lb/hour
Total NOx removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	8.63	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.06	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	35,456	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	27.93	/hour
Residence Time	$1/V_{space}$	0.04	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$		
Elevation Factor (ELEV) =	$14.7\ psia/P =$	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.25	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

10.2

Not applicable; factor applies only to coal-fired boilers

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$, where $Y = H_{catalyst} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.1739	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	1,269.42	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16\text{ft/sec} \times 60\text{ sec/min})$	37	ft ²

Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	12	feet
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SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	42	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	6.5	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	87	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft ³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	17	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	2.26	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	61.96	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEV F \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEV F \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV F \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV F \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEV F \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEV F \times RF$$

Total Capital Investment (TCI) =

\$5,593,742

in 2026 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =

\$52,789 in 2026 dollars

Indirect Annual Costs (IDAC) =

\$453,189 in 2026 dollars

Total annual costs (TAC) = DAC + IDAC

\$505,978 in 2026 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =

$$0.005 \times TCI =$$

\$27,969 in 2026 dollars

Annual Reagent Cost =

$$m_{sol} \times Cost_{reag} \times t_{op} =$$

\$905 in 2026 dollars

Annual Electricity Cost =

$$P \times Cost_{elect} \times t_{op} =$$

\$7,212 in 2026 dollars

Annual Catalyst Replacement Cost =

\$16,704 in 2026 dollars

$$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$$

Direct Annual Cost =

\$52,789 in 2026 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =

$$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$$

\$2,334 in 2026 dollars

Capital Recovery Costs (CR)=

$$CRF \times TCI =$$

\$450,856 in 2026 dollars

Indirect Annual Cost (IDAC) =

$$AC + CR =$$

\$453,189 in 2026 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =

\$505,978 per year in 2026 dollars

NOx Removed =

8.63 tons/year

Cost Effectiveness =

\$58,662 per ton of NOx removed in 2026 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(March 2021)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2016 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SNCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial ▼

What type of fuel does the unit burn?

Natural Gas ▼

Is the SNCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.25

* NOTE: You must document why a retrofit factor of 1.25 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

98.8 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

132,810,000 scf/Year

Is the boiler a fluid-bed boiler?

No ▼

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable ▼

Enter the sulfur content (%S) =

percent by weight

or

Select the appropriate SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table					
	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	12,000	2.4
Sub-Bituminous	0	0.41	5.84	9,000	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})

222 days

Plant Elevation

700 Feet above sea level

Number of days the boiler operates (t_{plant})	222 days
Inlet NO _x Emissions (NO _{x,in}) to SNCR	0.149 lb/MMBtu
Outlet NO _x Emissions (NO _{x,out}) from SNCR	0.093 lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05
Concentration of reagent as stored (C_{stored})	50 Percent
Density of reagent as stored (ρ_{stored})	71 lb/ft ³
Concentration of reagent injected (C_{inj})	10 percent
Number of days reagent is stored (t_{storage})	14 days
Estimated equipment life	20 Years

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019).

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Select the reagent used Urea ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2026
CEPCI for 2026	850 Enter the CEPCI value for 2026 541.7 2016 CEPCI
Annual Interest Rate (i)	7 Percent
Fuel (Cost _{fuel})	3.50 \$/MMBtu
Reagent (Cost _{reag})	2.50 \$/gallon for a 50 percent solution of urea
Water (Cost _{water})	0.0042 \$/gallon*
Electricity (Cost _{elect})	0.0850 \$/kWh
Ash Disposal (for coal-fired boilers only) (Cost _{ash})	\$/ton

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	\$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf .	\$2.50; accounted for cost escalation from 2021 to 2026.

Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf).	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	\$0.085 per kWh; per information provided by Howmet
Fuel Cost (\$/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf .	\$3.50; accounted for cost escalation from 2021 to 2026
Ash Disposal Cost (\$/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	98.8	MMBtu/hour
Maximum Annual fuel consumption (m_{fuel}) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/HHV =$	848,517,647	scf/Year
Actual Annual fuel consumption (M_{actual}) =		132,810,000	scf/Year
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.82	
Total System Capacity Factor (CF_{total}) =	$(M_{actual}/M_{fuel}) \times (t_{SNCR}/t_{plant}) =$	0.157	fraction
Total operating time for the SNCR (t_{op}) =	$CF_{total} \times 8760 =$	1371	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	37.6	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	5.53	lb/hour
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	3.79	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$	#VALUE!	
Elevation Factor (ELEV _F) =	$14.7 \text{ psia}/P =$	1.025	
Atmospheric pressure at 700 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.34	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.25	

Not applicable; factor applies only to coal-fired boilers

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NO_{x_{in}} \times Q_B \times NSR \times MW_R)/(MW_{NO_x} \times SR) =$ (whre SR = 1 for NH ₃ ; 2 for Urea)	10	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol} =$	20	lb/hour
	$(m_{sol} \times 7.4805)/\text{Reagent Density} =$	2.13	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24 \text{ hours/day})/\text{Reagent Density} =$	800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / (1+i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times \text{Q}_B) / \text{NPHR} =$	0.886	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	9.67	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$\text{Hv} \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.0817	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$773,397 in 2026 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2026 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,166,311 in 2026 dollars
Total Capital Investment (TCI) =	\$2,521,620 in 2026 dollars

#VALUE!

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$773,397 in 2026 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2026 dollars
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#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,166,311 in 2026 dollars
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Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$45,662 in 2026 dollars
Indirect Annual Costs (IDAC) =	\$239,176 in 2026 dollars
Total annual costs (TAC) = DAC + IDAC	\$284,838 in 2026 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$37,824 in 2026 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$7,287 in 2026 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$103 in 2026 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$55 in 2026 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$392 in 2026 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2026 dollars
Direct Annual Cost =		\$45,662 in 2026 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$1,135 in 2026 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$238,041 in 2026 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$239,176 in 2026 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$284,838 per year in 2026 dollars
NOx Removed =	4 tons/year
Cost Effectiveness =	\$75,095 per ton of NOx removed in 2026 dollars

Attachment 2

RACT NOx Control Options Cost Summary Workbook

NOx RACT Control Cost Workbook - Formula Notes	
Purpose	Supporting calculation workbook for Howmet B008/B009 NOx RACT control cost tables. Cost Detail contains only line-item costs; Summary by Technology has one row per control option; Tables 10-1 and 10-2 automatically compile values from the summary and and supporting calculation worksheets.
Workbook structure	
Capital Recovery/Annualization Factor	Capital Recovery = (Annualized Cost - Total Annual O&M Cost) / Total Capital Cost.
Annualized Cost	Annualized Cost = (Total Capital Cost × Annualization Factor) + Total Annual O&M Cost.
Estimated NOx Removed	NOx Removed = Baseline Annual NOx Emissions × Assumed Control Reduction.
Cost Effectiveness	Cost Effectiveness = Annualized Cost ÷ NOx Removed. Cost estimates are based on EPA cost methodologies, study-level engineering assumptions, and available project information developed for the draft RACT evaluation. Values remain screening-level estimates unless refined through additional vendor/OEM quotations, during Agency review.
Source/Basis	
SCR Retrofit Factor Basis	EPA SCR Cost Manual workbook retrofit factor of 1.25 applied to reflect moderate retrofit complexity for existing natural gas-fired package boilers, including duct routing, structural integration, outage coordination, and balance-of-plant modifications. Screening-level capital cost estimates were escalated to 2026 dollars using a representative Chemical Engineering Plant Cost Index (CEPCI) value of 850. Escalation was applied for consistency across control technology cost estimates and reflects approximate early-2026 industrial equipment and construction pricing conditions.
CEPCI Basis	The EPA SCR Cost Manual workbook develops base capital costs using embedded EPA reference-year cost correlations. Workbook outputs were escalated internally to representative 2026 dollars using a CEPCI value of 850 relative to the EPA workbook base CEPCI value of 541.7. For the representative SCR retrofit case, the underlying retrofit capital estimate of approximately \$3.565 million was escalated to approximately \$5.594 million in 2026 dollars using the ratio 850/541.7.
CEPCI Escalation Methodology	A 7% interest/discount rate was applied for annualization of control costs. The selected rate is intended to represent a reasonable screening-level financing and capital recovery assumption under approximate May 2026 economic conditions.
Interest Rate Basis	SCR/SNCR operator labor costs were evaluated using a screening-level labor rate of \$75/hour to reflect representative skilled industrial operating and maintenance labor costs under early-2026 conditions.
Operator Labor Rate Basis	SCR/SNCR electricity costs were evaluated using a representative screening-level industrial electricity rate of \$85/MWh (\$0.085/kWh) based on facility-provided information indicating approximate early-2026 electricity pricing conditions. Actual facility electricity costs may vary based on market conditions and utility pricing structure.
Electricity Cost Basis	Annualized capital costs were calculated using a Capital Recovery Factor (CRF) based on a 7% interest/discount rate and a 30-year equipment life for major SCR/SNCR control systems. The CRF converts total installed capital cost into an equivalent annual cost for screening-level cost effectiveness evaluation.
Capital Recovery Factor (CRF)	Annualized capital costs were calculated using the workbook’s Fixed Worth Factor (FWF), which is based on a 7% interest/discount rate and the selected equipment life. The FWF converts total installed capital cost into an equivalent uniform annual capital cost for screening-level cost-effectiveness evaluation.
Fixed Worth Factor (FWF)	SCR Total Capital Investment (TCI) estimates were developed using the U.S. EPA SCR Cost Manual workbook methodology for natural gas-fired industrial boilers. Because the Howmet B008/B009 boilers (98.8 MMBtu/hr each) are below the lower nominal applicability threshold of the EPA industrial boiler correlation (205 MMBtu/hr), the workbook equation was applied as a screening-level extrapolation for a smaller package boiler retrofit application. The applicable EPA workbook correlation is: TCI = 10,530 × (1,640/QB)^0.35 × QB × ELEVF × RF, where QB is boiler heat input (MMBtu/hr), ELEVF is the elevation correction factor, and RF is the retrofit factor. Boiler heat input was based on a 98.8 MMBtu/hr maximum firing rate using a natural gas higher heating value (HHV) of 1,020 Btu/scf.
SCR TCI Formula Basis	
Total Annual Cost (TAC)	Total Annual Cost (TAC) is the sum of Direct Annual Costs (DAC) and Indirect Annual Costs (IDAC), consistent with the EPA SCR Cost Manual methodology. TAC represents the total equivalent annual cost of owning and operating the evaluated control technology.
Direct Annual Costs (DAC)	Direct Annual Costs include annual maintenance, reagent consumption, electricity usage, and catalyst replacement costs associated with routine SCR operation. These costs represent recurring annual operating expenses.
Annual Maintenance Cost	Annual maintenance cost was calculated using the EPA SCR workbook default assumption of 0.5% of Total Capital Investment (TCI) per year (0.005 × TCI). This factor represents routine mechanical, electrical, instrumentation, and controls maintenance associated with SCR operation.
Annual Reagent Cost	Annual reagent cost was calculated based on estimated ammonia consumption, annual operating hours, and reagent unit pricing assumptions embedded within the EPA SCR workbook methodology. Reagent consumption is derived from estimated NOx removal, stoichiometric reagent demand, and selected SCR operating assumptions.
Annual Electricity Cost	Annual electricity cost was calculated based on estimated SCR electrical demand (including fan and auxiliary loads), annual operating hours, and the selected screening-level electricity rate of \$85/MWh (\$0.085/kWh). Electrical demand is estimated internally by the EPA SCR workbook based on flue gas flow and SCR pressure drop assumptions.
Annual Catalyst Replacement Cost	Annual catalyst replacement cost represents the annualized equivalent cost of periodic catalyst replacement over the selected catalyst life. The EPA SCR workbook estimates catalyst volume requirements and replacement frequency based on flue gas flow, catalyst space velocity, and selected operating assumptions.
Indirect Annual Costs (IDAC)	Indirect Annual Costs include administrative charges and annualized capital recovery costs associated with ownership of the SCR system.
Administrative Charges	Administrative charges were calculated using the EPA SCR workbook default assumption of 15% of Direct Annual Costs. Administrative costs represent procurement, management, administrative support, and overhead-related expenses associated with operation of the SCR system.
Capital Recovery Costs (CR)	Capital recovery cost represents the annualized equivalent cost of Total Capital Investment (TCI) using the workbook Fixed Worth Factor (FWF) methodology. The FWF is based on the selected 7% interest/discount rate and equipment life assumptions.
Cost Effectiveness	Cost effectiveness was calculated as Total Annual Cost divided by annual NOx removed (\$/ton NOx removed). Annual NOx removed was determined using representative baseline NOx emissions and assumed SCR control efficiency.
NOx Removed	Annual NOx removed was estimated based on representative baseline NOx emissions and assumed control efficiency for each evaluated technology. For SCR, an 85% NOx reduction efficiency was applied consistent with representative EPA SCR guidance values for natural gas-fired industrial boilers.

Input	B008	B009	Notes
2025 Actual NOx Baseline (TPY)	11.46	10.16	From 2025 actual fuel consumption.
PTE Baseline (TPY)	64.91	64.91	From boiler maximum heat rating (98.8 MMBtu/hr), permit limit (0.15 lb/MMBtu) and 8760 hr/yr. PTE sensitivity basis.
April 2026 Baseline NOx Rate (lb/MMBtu)	0.125	0.149	Representative measured rates used for controlled-rate screening.
Presumptive RACT Limit (lb/MMBtu)	0.08	0.08	OAC 3745-110 mid-size gas-fired boiler presumptive limit.
Proposed Source-Specific RACT Limit (Existing Permit Basis), lb/MMBtu	0.15	0.15	Existing Title V permit (Permit No. PD135538; effective date, February 11, 2025; expiration date, February 11, 2030) compliance emission factor established from 2010 stack testing and used for current NOx compliance determinations. Evaluated in this study as the proposed source-specific RACT limit

Technology	Estimated Reduction Efficiency ¹	Study Annualized Cost (\$/yr) ⁴	Notes
Combustion tune-up / burner optimization ¹	10.0%	\$26,207	Typical combustion optimization reduction range based on engineering judgment and industry practice.
Oxygen trim / controls modernization ¹	15.0%	\$67,828	Representative reduction estimate for improved combustion control systems.
Low excess air optimization ¹	10.0%	\$38,414	Representative reduction estimate for excess air optimization.
FGR retrofit / fan and duct modifications ²	37.5%	\$253,545	Screening-level estimate based on typical FGR performance for package boilers.
LNB/LULNB with FGR and combustion controls ²	65.0%	\$376,217	Screening-level estimate based on 2026 vendor proposal information, vendor literature, and representative industrial package boiler retrofit performance ranges.
SNCR ³	37.5%	\$264,838	Typical screening-level NOx reduction estimate from EPA control guidance and SNCR Workbook calculation.
SCR ³	85.0%	\$505,978	Typical screening-level NOx reduction estimate from EPA SCR guidance and SCR Workbook calculation.

¹Combustion optimization, oxygen trim, and low excess air reduction efficiencies are representative engineering estimates based on typical industrial boiler combustion optimization practices and operational tuning ranges reported in EPA combustion control guidance and industry literature.

²FGR and LNB/LULNB reduction efficiencies are screening-level estimates based on typical retrofit performance ranges reported in EPA NOx control guidance, vendor literature, and prior industrial package boiler retrofit evaluations.

³SNCR and SCR reduction efficiencies are representative screening-level values derived from EPA Air Pollution Control Cost Manual methodologies and EPA NOx control technology guidance documents. SNCR and SCR annualized costs shown in this worksheet were derived from separate EPA Air Pollution Control Cost Manual screening workbooks completed for the subject boilers using representative 2026 operating assumptions, measured April 2026 baseline emission rates, and study-level retrofit design assumptions. The resulting total annualized costs (TAC) from the EPA workbooks were used directly in this comparative RACT evaluation. These values represent screening-level engineering-economic estimates intended for comparative RACT evaluation purposes and do not represent final engineered construction costs or binding contractor proposals.

⁴Reduction efficiencies are relative to current baseline boiler operation under representative operating conditions.

⁵Annualized costs shown in this table are representative study-level estimates on a per-boiler basis unless otherwise specifically identified. Combined B008+B009 annualized costs used in comparative cost-effectiveness evaluations are calculated separately in the applicable summary and sensitivity-analysis tables.

Ref. U.S. EPA Air Pollution Control Cost Manual, Sixth Edition (2019), Section 1 – Selective Catalytic Reduction and Selective Non-Catalytic Reduction.

Howmet NOx RACT Control Cost Detail - Screening-Level Cost Basis						
The following cost elements represent conceptual screening-level retrofit implementation categories used to develop comparative annualized cost estimates for candidate NOx control technologies evaluated in the NOx RACT engineering study. Costs are presented in 2026 dollars and are intended for comparative RACT screening, not bid-level construction estimating.						
Technology	Cost Line Item	Initial / Capital Cost	Annual O&M / Annual Cost	Cost Treatment / Workbook Linkage	Notes / Basis	Source / Confidence
Combustion Optimization / Tune-Up						
Combustion tune-up / burner optimization	Initial field review and setup documentation	\$12,000	-	CAPEX/O&M build-up	Review existing burner settings, operating logs, and tune-up documentation; establish baseline field checklist.	Engineering judgment; study-level screening
Combustion tune-up / burner optimization	Initial tune and annual retune	\$18,000	\$12,000	CAPEX/O&M build-up	Initial burner tune-up plus representative annual retune labor and combustion optimization support.	Engineering judgment; typical combustion optimization practice
Combustion tune-up / burner optimization	Initial and annual verification testing support	\$7,000	\$3,000	CAPEX/O&M build-up	Portable analyzer support, verification checks, and limited combustion performance documentation.	Engineering judgment; screening estimate
Combustion tune-up / burner optimization	Procedures, checklist, and training updates	\$3,000	\$1,000	CAPEX/O&M build-up	Update tune-up procedures, operating checklists, and operator support materials.	Engineering judgment; screening estimate
Combustion tune-up / burner optimization	Study-level allowance	\$5,000	\$2,000	CAPEX/O&M build-up	Allowance for minor follow-up optimization, documentation, and field support uncertainty.	Conceptual screening allowance
Combustion tune-up / burner optimization	Subtotal - Combustion tune-up / burner optimization	\$45,000	\$18,000			
Oxygen Trim / Controls Modernization						
Oxygen trim / controls modernization	Analyzer probe, sample conditioning, calibration gases	\$45,000	\$8,000	CAPEX/O&M build-up	Representative allowance for oxygen analyzer hardware, sample conditioning, calibration gases, and routine analyzer support.	Engineering judgment; industrial controls screening
Oxygen trim / controls modernization	Controls and mechanical trim items	\$20,000	\$6,000	CAPEX/O&M build-up	Minor mechanical trim components and field materials needed to support oxygen trim and combustion-control modernization.	Engineering judgment; screening estimate
Oxygen trim / controls modernization	PLC/DCS integration and programming	\$40,000	\$6,000	CAPEX/O&M build-up	Controls integration, programming, trends/alarms, and coordination with existing boiler control system.	Engineering judgment; controls integration screening
Oxygen trim / controls modernization	Installation, checkout, and commissioning	\$55,000	\$9,000	CAPEX/O&M build-up	Field installation, checkout, commissioning, and tuning support under operating boiler conditions.	Engineering judgment; screening estimate
Oxygen trim / controls modernization	Testing, training, and contingency allowance	\$20,000	\$6,000	CAPEX/O&M build-up	Operator training, testing support, and contingency for integration uncertainty.	Conceptual screening allowance
Oxygen trim / controls modernization	Subtotal - Oxygen trim / controls modernization	\$180,000	\$35,000			
Low Excess Air Optimization						
Low excess air optimization	Combustion tuning and instrumentation review	\$25,000	\$5,000	CAPEX/O&M build-up	Combustion tuning review, instrumentation check, and air/fuel optimization support.	Engineering judgment; typical combustion optimization
Low excess air optimization	Controls adjustments and burner settings	\$35,000	\$7,000	CAPEX/O&M build-up	Representative allowance for control adjustments, burner setup refinements, and field tuning.	Engineering judgment; screening estimate
Low excess air optimization	Verification testing	\$15,000	\$5,000	CAPEX/O&M build-up	Verification testing to confirm NOx, O2, CO, and combustion performance after optimization.	Engineering judgment; screening estimate
Low excess air optimization	Procedures and operator support	\$5,000	\$2,000	CAPEX/O&M build-up	Procedure updates and operator support for maintaining lower excess-air operation.	Engineering judgment; screening estimate
Low excess air optimization	Study-level contingency	\$10,000	\$3,000	CAPEX/O&M build-up	Representative contingency for combustion variability, follow-up tuning, and documentation.	Conceptual screening allowance
Low excess air optimization	Subtotal - Low excess air optimization	\$90,000	\$22,000			
FGR Retrofit / Fan and Duct Modifications						
FGR retrofit / fan and duct modifications	Fan margin, duct routing, stack takeoff, controls integration review	\$65,000	-	CAPEX/O&M build-up	Engineering review of fan capacity, FGR takeoff, duct routing, controls integration, and retrofit constructability.	Engineering judgment; retrofit screening
FGR retrofit / fan and duct modifications	Fan upgrade allowance	\$190,000	\$18,000	CAPEX/O&M build-up	Allowance for fan upgrade or fan system modifications to accommodate FGR flow and pressure drop.	Engineering judgment; package boiler retrofit screening
FGR retrofit / fan and duct modifications	Ductwork and installation allowance	\$240,000	\$26,000	CAPEX/O&M build-up	FGR ductwork, dampers, routing, mechanical installation, access, and stack/duct tie-in allowance.	Engineering judgment; retrofit screening
FGR retrofit / fan and duct modifications	Controls, interlocks, tuning, startup support	\$90,000	\$18,000	CAPEX/O&M build-up	Combustion controls, interlocks, startup tuning, and FGR/air-fuel balancing support.	Engineering judgment; controls/commissioning screening
FGR retrofit / fan and duct modifications	Study-level retrofit uncertainty allowance	\$65,000	\$8,000	CAPEX/O&M build-up	Representative contingency for retrofit uncertainty, outage coordination, access limitations, and installation complexity.	Conceptual screening allowance
FGR retrofit / fan and duct modifications	Subtotal - FGR retrofit / fan and duct modifications	\$650,000	\$70,000			
LNB/LULNB with IFGR and Combustion Controls						
LNB/LULNB with FGR and combustion controls	2026 vendor proposal base scope	\$997,619	-	CAPEX basis	Vendor proposal for burner and fan replacement and front-wall reconstruction, including low-NOx burner/IFGR-related scope, per boiler.	2026 vendor proposal; high confidence as screening anchor
LNB/LULNB with FGR and combustion controls	Owner-side integration / excluded-scope allowance	\$75,000	-	CAPEX adjustment	Allowance for excluded or owner-supplied elements such as electrical wiring, VFD/customer-supplied components, insulation, access support, and integration coordination.	Engineering allowance based on proposal exclusions
LNB/LULNB with FGR and combustion controls	Escalation, engineering, and contingency round-up	\$77,381	-	CAPEX adjustment	Representative adjustment to normalize proposal-based scope to a rounded \$1.15 million per-boiler screening capital estimate in 2026 dollars.	Conceptual screening allowance
LNB/LULNB with FGR and combustion controls	Annual burner/FGR tuning and verification support	-	\$20,000	Annual O&M	Representative annual combustion tuning, verification, and operational support for burner/FGR system.	Engineering judgment; screening estimate
LNB/LULNB with FGR and combustion controls	Controls/VFD/IFGR system maintenance support	-	\$20,000	Annual O&M	Representative annual support for controls, interlocks, VFD/fan/FGR components, and system checks.	Engineering judgment; screening estimate
LNB/LULNB with FGR and combustion controls	Annual contingency / operator support allowance	-	\$15,000	Annual O&M	Allowance for operator support, troubleshooting, tuning variability, and follow-up service.	Conceptual screening allowance
LNB/LULNB with FGR and combustion controls	Subtotal - LNB/LULNB with FGR and combustion controls	\$1,150,000	\$55,000		Single-boiler screening estimate.	
SNCR EPA Workbook-Derived Screening Costs						
SNCR	Total Capital Investment (TCI) from EPA SNCR workbook	\$2,521,620	-	EPA workbook TCI	Total capital investment from completed EPA SNCR cost workbook using 2026 inputs and study-level design assumptions.	EPA SNCR cost workbook; high confidence for screening
SNCR	Direct Annual Cost (DAC) from EPA SNCR workbook	-	\$45,662	EPA workbook DAC	Direct annual cost from completed EPA SNCR workbook. Includes annual maintenance, reagent, electricity, water, fuel, and related direct annual cost categories.	EPA SNCR cost workbook
SNCR	Indirect Annual Cost (IDAC) from EPA SNCR workbook	-	\$239,176	EPA workbook IDAC	Indirect annual costs from completed EPA SNCR workbook, including capital recovery and administrative charges.	EPA SNCR cost workbook
SNCR	Total Annual Cost (TAC) cross-check	-	\$284,838	EPA workbook TAC	TAC = DAC + IDAC. This value is used as the Study Annualized Cost in the comparative RACT tables.	EPA SNCR cost workbook output
SNCR	Reference Total - SNCR EPA workbook outputs	\$2,521,620	\$284,838		Single-boiler screening estimate.	
SCR EPA Workbook-Derived Screening Costs						
SCR	Total Capital Investment (TCI) from EPA SCR workbook	\$5,593,742	-	EPA workbook TCI	Total capital investment from completed EPA SCR cost workbook using 2026 inputs and study-level design assumptions.	EPA SCR cost workbook; high confidence for screening
SCR	Direct Annual Cost (DAC) from EPA SCR workbook	-	\$52,789	EPA workbook DAC	Direct annual cost from completed EPA SCR workbook. Includes maintenance, reagent, electricity, catalyst replacement, and related direct annual cost categories.	EPA SCR cost workbook
SCR	Indirect Annual Cost (IDAC) from EPA SCR workbook	-	\$453,189	EPA workbook IDAC	Indirect annual costs from completed EPA SCR workbook, including capital recovery and administrative charges.	EPA SCR cost workbook
SCR	Total Annual Cost (TAC) cross-check	-	\$505,978	EPA workbook TAC	TAC = DAC + IDAC. This value is used as the Study Annualized Cost in the comparative RACT tables.	EPA SCR cost workbook output
SCR	Reference Total - SCR EPA workbook outputs	\$5,593,742	\$505,978		Single-boiler screening estimate.	
General Cost-Basis Notes						
General	Screening-level accuracy statement			Workbook note	Cost elements are conceptual engineering-economic screening values for comparative RACT evaluation. They are generally expected to fall within a representative study-level accuracy range of approximately plus/minus 50 percent unless derived directly from EPA workbook outputs or vendor proposal information.	Engineering-economic screening convention
General	Use limitation			Workbook note	Values do not represent final engineered construction estimates, procurement quotes, or contractor bids. Major retrofit costs should be refined by vendor/OEM quotations and detailed engineering if a final implementation determination is required.	Study limitation statement

Estimated costs presented in this worksheet are intended for comparative RACT screening purposes and represent conceptual engineering-economic retrofit estimates for existing industrial package boilers under representative 2026 operating assumptions. These values are not final engineered construction estimates or binding contractor proposals.

Technology	Assumed Reduction	CAPEX	Annual O&M	Total Annualized Cost	Total Capital Investment (TCI)	Direct Annual Cost (DAC)	Total Annual Cost (TAC)	Indirect Annual Costs (IDAC)	Implied Annualization Factor ⁴	Formula Annualized Cost	Check
Combustion tune-up / burner optimization ¹	10.0%	\$45,000	\$18,000	\$26,207					18.2%	\$26,207	OK
Oxygen trim / controls modernization ¹	15.0%	\$180,000	\$35,000	\$67,828					18.2%	\$67,828	OK
Low excess air optimization ¹	10.0%	\$90,000	\$22,000	\$38,414					18.2%	\$38,414	OK
FGR retrofit / fan and duct modifications ¹	37.5%	\$650,000	\$70,000	\$253,545					28.2%	\$253,545	OK
LNB/ULNB with FGR and combustion controls ^{2,3}	46.7%	\$1,150,000	\$55,000	\$163,300					9.4%	\$163,300	OK
SNCR ⁵	37.5%	\$2,521,620	\$37,824	\$294,838	\$2,521,620	\$45,662	\$284,838	\$239,176	9.8%	\$294,838	OK
SCR ⁵	85.0%	\$5,593,742	\$27,969	\$505,978	\$5,593,742	\$2,789	\$505,978	\$453,189	8.5%	\$505,978	OK

¹Source materials for combustion-control cost and reduction estimates included EPA Air Pollution Control Cost Manual methodologies, combustion optimization guidance, industrial boiler retrofit literature, prior facility-specific engineering evaluations, and representative engineering judgment for retrofit implementation at existing industrial package boilers. Estimated costs represent study-level screening estimates in 2026 dollars intended for comparative RACT evaluation purposes. Consistent with conceptual engineering-economic evaluations of retrofit technologies, these estimates are considered approximate screening-level values and are generally expected to fall within a representative study-level accuracy range of approximately ±50%.

²The estimated LNB/ULNB with IFGR retrofit capital cost was developed using a 2026 vendor proposal for burner replacement and front wall reconstruction at approximately \$997,619 per boiler. The screening-level cost estimate was adjusted to account for representative escalation to 2026 dollars, controls integration, startup and commissioning support, installation complexity, outage coordination, engineering allowance, and contingency appropriate for retrofit implementation at an operating industrial facility. Estimated costs are presented on a per-boiler basis. The resulting cost estimate is intended for comparative RACT screening purposes only and does not represent a final engineered construction estimate or binding contractor proposal.

³The LNB/ULNB with IFGR annualized cost was calculated using a capital annualization factor plus annual O&M. The capital annualization factor shown in Column J is calculated as (Total Annualized Cost – Annual O&M) ÷ CAPEX, which isolates the capital recovery portion of the annualized cost. For this screening-level estimate, the capital recovery portion is approximately 9.4%, consistent with a 7% discount rate and 20-year project life. Annual O&M is then added separately to calculate total annualized cost. Thus, for the LNB/ULNB with IFGR case: \$1,150,000 × 9.4% + \$55,000 = \$163,300 per boiler per year.

⁴The implied annualization factor shown in Column J represents the capital recovery portion of the total annualized cost and is calculated as: Implied Annualization Factor (IAF) = (Total Annualized Cost – Annual O&M Cost) ÷ CAPEX. This factor reflects the effective annualized capital recovery rate associated with each control technology under the screening-level assumptions used in this evaluation. For retrofit technologies with developed capital estimates, the implied factor generally reflects representative project financing assumptions, equipment life, installation complexity, and indirect implementation costs consistent with conceptual engineering-economic evaluations. The worksheet formula applied in Column J is: IF (CAPEX = 0, return 0; otherwise: (TAC – Annual O&M) ÷ CAPEX. For example, for the combustion tune-up / burner optimization screening estimate: (26,207 – 18,000) ÷ 45,000 = 0.182 = 18.2%. The implied annualization factors presented in this study are intended solely for comparative RACT screening purposes and do not represent detailed project financing analyses or final engineered construction estimates.

⁵SNCR and SCR annualized costs shown in this worksheet were derived from separate EPA Air Pollution Control Cost Manual screening workbooks completed for the subject boilers using representative 2026 operating assumptions, measured April 2026 baseline NOx emission rates, and study-level retrofit design assumptions. The resulting total annualized costs (TAC) from the EPA workbooks were used directly in this comparative RACT evaluation. These values represent screening-level engineering-economic estimates intended for comparative RACT evaluation purposes and do not represent final engineered construction costs or binding contractor proposals. Because the EPA workbook methodologies internally incorporate capital recovery, indirect annual costs, maintenance, utilities, reagent usage, and operating assumptions, the resulting TAC values were used directly rather than recalculated using the simplified implied annualization factor methodology applied to the conceptual combustion-control retrofit estimates.

Study-Level Engineering Cost Basis Note:

The cost estimates and annualized cost values presented in this workbook represent conceptual, study-level engineering estimates prepared for comparative RACT screening and cost-effectiveness evaluation purposes. These values are intended to support relative evaluation of NOx control alternatives and do not represent final engineered construction costs, procurement quotations, or binding contractor proposals. Actual implementation costs may vary depending on detailed engineering, vendor selection, outage scope, constructability, equipment integration requirements, and site-specific field conditions.

Table 10-1. Cost Effectiveness Relative to 2025 Actual Baseline and PTE Sensitivity

Technology	Boiler	Assumed Reduction	Annualized Cost (\$/yr)	2025 Actual Baseline (TPY)	NOx Removed Actual (TPY)	Actual-Basis Cost Effectiveness (\$/ton)	PTE Baseline (TPY)	NOx Removed PTE (TPY)	PTE-Basis Cost Effectiveness (\$/ton)
Combustion tune-up / burner optimization	B008	10.0%	\$26,207	11.46	1.15	\$22,868	64.91	6.49	\$4,037
Combustion tune-up / burner optimization	B009	10.0%	\$26,207	10.16	1.02	\$25,794	64.91	6.49	\$4,037
Oxygen trim / controls modernization	B008	15.0%	\$67,828	11.46	1.72	\$39,458	64.91	9.74	\$6,966
Oxygen trim / controls modernization	B009	15.0%	\$67,828	10.16	1.62	\$44,507	64.91	9.74	\$6,966
Low excess air optimization	B008	10.0%	\$38,414	11.46	1.15	\$33,520	64.91	6.49	\$5,918
Low excess air optimization	B009	10.0%	\$38,414	10.16	1.02	\$37,809	64.91	6.49	\$5,918
FGR retrofit / fan and duct modifications	B008	37.5%	\$253,545	11.46	4.30	\$58,998	64.91	24.34	\$10,416
FGR retrofit / fan and duct modifications	B009	37.5%	\$253,545	10.16	3.81	\$66,547	64.91	24.34	\$10,416
LNB/LULNB with FGR and combustion controls	B008	46.7%	\$163,300	11.46	5.35	\$30,513	64.91	30.31	\$5,387
LNB/LULNB with FGR and combustion controls	B009	46.7%	\$163,300	10.16	4.74	\$34,417	64.91	30.31	\$5,387
SNCR	B008	37.5%	\$284,838	11.46	4.30	\$66,280	64.91	24.34	\$11,702
SNCR	B009	37.5%	\$284,838	10.16	3.81	\$74,761	64.91	24.34	\$11,702
SCR	B008	85.0%	\$505,978	11.46	9.74	\$51,943	64.91	55.17	\$9,171
SCR	B009	85.0%	\$505,978	10.16	8.64	\$58,589	64.91	55.17	\$9,171

Table 10-2. Decision-Focused Cost Effectiveness Screen Relative to Presumptive RACT Limit and PTE Sensitivity

Technology	Boiler	Baseline NOx Rate (lb/MMBtu)	Reduction	Annualized Cost	Controlled Rate (lb/MMBtu)	Potential to Meet 0.08?	Representative Annual NOx Removed (TPY)	Representative Operating Basis (\$/ton removed)	PTE-Based Annual NOx Reduction (TPY)	PTE Sensitivity Basis (\$/ton removed)
Combustion tune-up / burner optimization	B008	0.125	10.0%	\$26,207	0.113	No	1.15	\$22,868	6.49	\$4,037
Combustion tune-up / burner optimization	B009	0.149	10.0%	\$26,207	0.134	No	1.02	\$25,794	6.49	\$4,037
Oxygen trim / controls modernization	B008	0.125	15.0%	\$67,828	0.106	No	1.72	\$39,458	9.74	\$6,966
Oxygen trim / controls modernization	B009	0.149	15.0%	\$67,828	0.127	No	1.52	\$44,507	9.74	\$6,966
Low excess air optimization	B008	0.125	10.0%	\$38,414	0.113	No	1.15	\$33,520	6.49	\$5,918
Low excess air optimization	B009	0.149	10.0%	\$38,414	0.134	No	1.02	\$37,809	6.49	\$5,918
FGR retrofit / fan and duct modifications	B008	0.125	37.5%	\$253,545	0.078	Potentially	4.30	\$58,998	24.34	\$10,416
FGR retrofit / fan and duct modifications	B009	0.149	37.5%	\$253,545	0.093	Potentially	3.81	\$66,547	24.34	\$10,416
LNB/ULNB with FGR and combustion controls	B008	0.125	46.7%	\$163,300	0.067	Potentially	5.35	\$30,513	30.31	\$5,387
LNB/ULNB with FGR and combustion controls	B009	0.149	46.7%	\$163,300	0.079	Potentially	4.74	\$34,417	30.31	\$5,387
SNCR	B008	0.125	37.5%	\$284,838	0.078	Uncertain	4.30	\$66,280	24.34	\$11,702
SNCR	B009	0.149	37.5%	\$284,838	0.093	Uncertain	3.81	\$74,761	24.34	\$11,702
SCR	B008	0.125	85.0%	\$505,978	0.019	Demonstrated	9.74	\$51,943	55.17	\$9,171
SCR	B009	0.149	85.0%	\$505,978	0.022	Demonstrated	8.64	\$58,589	55.17	\$9,171

Notes

"Demonstrated" indicates a technology with established commercial capability for achieving the referenced emission level on comparable combustion sources, subject to site-specific engineering design.

"Potentially" indicates that screening-level engineering evaluation suggests the referenced emission level may be achievable, but additional vendor review, combustion evaluation, or detailed engineering would be required for confirmation.

"Uncertain" indicates that available information does not currently demonstrate reliable technical applicability or performance capability for the subject boilers.

Appendix D. Sensitivity of NOx Control Cost Effectiveness to Baseline Operating Assumptions

Technology	Representative Reduction Assumption	Annualized Cost (\$/yr)	Combined 2025 Actual Baseline (TPY)	NOx Removed Actual (TPY)	Actual-Basis Cost Effectiveness (\$/ton)	Combined PTE Baseline (TPY)	PTE NOx Removed (TPY)	PTE-Basis Cost Effectiveness (\$/ton)
Combustion tune-up / burner optimization	10.0%	\$26,207	21.62	2.16	\$12,122	129.82	12.98	\$2,019
Oxygen trim / controls modernization	15.0%	\$67,828	21.62	3.24	\$20,915	129.82	19.47	\$3,483
Low excess air optimization	10.0%	\$38,414	21.62	2.16	\$17,768	129.82	12.98	\$2,959
FGR retrofit / fan and duct modifications	37.5%	\$263,545	21.62	8.11	\$31,273	129.82	48.68	\$5,208
LNB/ULNB with FGR and combustion controls	46.7%	\$163,300	21.62	10.10	\$16,174	129.82	60.63	\$2,694
SNCR	37.5%	\$284,838	21.62	8.11	\$35,133	129.82	48.68	\$5,851
SCR	85.0%	\$505,978	21.62	18.38	\$27,533	129.82	110.35	\$4,585

Attachment 3

NBW Inc. Burner and Fan Replacement Cost Proposal for Boilers B008 and B009



**INDUSTRIAL
MECHANICAL
CONTRACTOR**

**4556 Industrial Pkwy,
Cleveland, OH 44135
216.377.1700
www.nbwinc.com
OH.LIC 25040**

04/28/2026

Howmet Aerospace
1600 Harvard Avenue
Cleveland, OH 44105

Attn: Mike Lucek
Email: Michael.Lucek@howmet.com

Subject: Burner and Fan replacement and front wall replacement.
Proposal: NBW0426-283
Valid through: 05/30/2026

Dear Sir:

NBW, Inc. is pleased to offer the following proposal to upgrade the existing Nebraska boiler with a new Low NOx burner and Arrangement 4 forced draft fan and a complete new front wall as detailed below.

LOW NOx PACKAGE BURNER

We have selected an NBW Low NOx Package Burner. Please find our proposal for the supply Low NOx package burners.

Each proposed burners will consist of a windbox, register, throat, forced draft fan, IFGR equipment, pilot gas ignition train, main gas train, miscellaneous safety switches, and burner wiring.

WINDBOX ASSEMBLY

- One (1) Heavy Duty Windbox, ¼" steel plate, with ¾" top plate, properly stiffened and reinforced and designed to receive an even air distribution from the forced draft fan.
- One (1) Bolted Access Door
- One (1) Set of Instrument and Drain Connections, plugged pipe couplings for windbox pressure gauge connection, windbox drain, and other connections as required.

REGISTER ASSEMBLY

- One (1) NBW model VPSSS-22 Venturi Type Register, forced draft, with adjustable air vanes. Vanes can be adjusted for a clockwise or counter-clockwise rotation to suit the furnace parameters.
- Two (2) 2 ½" Observation Ports with sight glass
- One (1) Flame Scanner Mount with Adjustable Ball Swivel Assembly and factory piped cooling air
- One (1) Heavy Duty Jacket Tube Support
- One (1) Jacket Tube
- One (1) Diffuser, high temperature stainless steel
- One (1) NBW Gas/Electric Igniter, class 3 rating

- One (1) Main Gas Ring with high temperature stainless spud assemblies

FORCED DRAFT FAN ASSEMBLY

High efficiency arrangement, windbox mounted in field, consisting of:

- One (1) Forced Draft Fan, arrangement 4, airfoil type (Chicago Blower)
- One (1) 150 HP Electric Motor, 1780 RPM, premium efficient TEFC type suitable for operation by a variable frequency drive (VFD)
- One (1) Inlet Vortex Vane Air Flow Control Damper, low leakage type, for optimum air control and fan performance
- One (1) Actuator to operate above damper (Air Torque with ABB Positioner), pneumatically operated with positioner, feedback position transmitter, air-set with gauge, limit switch and proper linkage to damper. Control signal (4 to 20 maDC) to positioner to be from combustion control system.
- One (1) Silencer, field mounted on mixing box forced draft fan inlet, designed to reduce the noise level to approximately 85 dBA five feet from the silencer inlet. The silencer will be equipped with a velocity-probe airflow element.

NOTE: VFD for the Forced Draft Fan to be by others.

INDUCED FLUE GAS RECIRCULATION SYSTEM

Reduction of nitrous oxide emissions will be accomplished through the use of the NBW Venturi Profile Low NOx Burner in combination with induced flue gas recirculation (IFGR) to meet the projects NOx requirement in the most cost-effective means. The FD fan will function as the prime mover for the flue gas recirculation.

The following will be shipped loose:

- One (1) Stack Scoop to aid in the recirculation of the flue gas.
- Two (2) Rolled Angle Flanges (for connecting ducting to scoop and to damper).
- One (1) IFGR Flow Control Damper with pneumatic operated actuator, (Air Torque with ABB Positioner). Control signal (4 to 20 maDC) to this damper to be from combustion system controller.
- One (1) IFGR/Air Inlet Mixing Box with pneumatic operated fresh air inlet damper (Air Torque with ABB Positioner), for mounting on FD fan inlet

NOTE: IFGR ducting by others; minimum 14" diameter, schedule 10 required.

PILOT GAS IGNITION TRAIN

Factory piped, installed, and wired, with schedule 80 carbon steel threaded pipe and 3000 psig fittings. The pilot train will be comprised of valves with aluminum, bronze, cast iron and steel bodies.

The following will be provided:

- One (1) Pilot Gas Flex Hose – 321 stainless steel construction, braided
- One (1) Pilot Gas Hose Shutoff Valve – 3 Piece Full Port Ball Valve (Apollo)
- Two (2) Leak Test Valves
- Two (2) Pilot Gas Shutoff Valves – normally closed (ASCO)
- **One (1) Pilot Gas Vent Valve – normally open (ASCO)**
- One (1) Pressure Gauge, 4 ½" Dial
- One (1) Pilot Gas Pressure Regulator – (American Meter)
- One (1) Strainer – with 150-mesh screen
- One (1) Pilot Gas Train Supply Shutoff Valve – 3 Piece Full Port Ball Valve (Apollo)
- One (1) Ignition Transformer-10,000 VAC output, mounted in a NEMA 4 enclosure on the burner
- One (1) High Temperature Ignition Cable Assembly

MAIN GAS TRAIN

Factory installed, wired and piped with Schedule 40 ASTM A-106 Grade B seamless steel pipe, with standard butt-weld fittings and 150 lb. flanges for nominal 3" diameter and larger lines, and Schedule 40 ASTM A-106 Grade B seamless steel pipe and 3,000 lb. threaded fittings for nominal 2 ½" diameter and smaller lines. The natural gas train will be comprised of valves with aluminum, bronze, cast iron and steel bodies. Stainless steel tubing will be used in the installation of switches and gauges.

The following will be provided:

- One (1) Pressure Gauge with Shutoff Valve – 4 ½" dial
- One (1) Gas Flow Control Valve (Samson with ABB positioner) pneumatically operated with positioner, position feedback transmitter, air set with gauge and limit switch. Control signal (4 to 20 maDC) to the positioner to be from the combustion control system.
- One (1) Plug Valve with Wrench (Homestead)
- One (1) High Gas Pressure Switch (Ashcroft)
- One (1) Low Gas Pressure Switch (Ashcroft)
- Two (2) Gas Safety Shutoff Valves – normally closed, with proof of closure switches (Maxon)
- One (1) Gas Vent Manual Valve – 3 Piece Full Port Ball Valve, lockable in the open position (Apollo)
- One (1) Vent Valve, automatic, normally open, full port (ASCO)
- Two (2) Leak Test Manual Shutoff Valves, with plugs

The following will be shipped loose:

- One (1) Plug Valve with Wrench – (Homestead)
- One (1) "Y" Strainer
- One (1) Main Gas Pressure Reducing Valve (Fisher)
- One set (1) PRV Inlet and Outlet Pressure Gauge with Shutoff Valve – 4 ½" dial

MISCELLANEOUS SAFETY SWITCHES

The following will be provided:

- One (1) Fan Differential Pressure Limit Switch
- One (1) Forced Draft Damper Open Switch (Telemecanique)
- One (1) Forced Draft Damper Light-off Position Switch (Telemecanique)
- One (1) Fresh Air Draft Damper Open Switch (Telemecanique)
- One (1) FGR Damper Open Switch (Telemecanique)
- One (1) FGR Damper Closed Switch (Telemecanique)
- One (1) Purge Air Flow Pressure Limit Switch (Ashcroft)
- One (1) High Boiler Pressure Limit Switch (Ashcroft)
- One (1) Excess Boiler Pressure Limit Switch (Ashcroft)
- One (1) High Furnace Pressure Limit Switch (Ashcroft-shipped loose)
- One (1) Low Instrument Air Pressure Switch (Ashcroft)

WIRING

All mechanical switches, limit switches and valves mounted on the burner are wired to terminal strips in a NEMA 12 enclosure mounted on the burner.

PAINT & FINISH

Preparation

External Steel	SSPC-SP3
Piping/Fittings.....	SSPC-SP1
Electrical Panels	Manufacturers Standard

Instruments	Manufacturers Standard
Conduit	Manufacturers Standard

Primer:

All unprimed components are primed with (1) coat of Sherwin-Williams B50 Kem Bond HS primer.

Paint:

All unpainted components are painted with (2) coats of Western Automotive Finishes 3rd Dimension Urethane. Western Automotive Finishes is a division of Sherwin-Williams. The burner will be painted the same color as the boiler.

EMISSION GUARANTEES

Not to Exceed:	<u>Natural Gas</u>	
	<u>Lbs/MMBTU</u>	<u>PPM</u>
NOx	0.036	30
CO	0.037	50
Parts Per Million (PPM) @ 3% O2 Dry		

EMISSION TEST CONDITIONS:

For a valid guarantee test, the following conditions must be met:

1. Emission guarantees are based upon the data in the design conditions above and steady state operating conditions. Heat inputs listed as HHV.
2. Guarantees are from 25% to 100% MCR (maximum continuous rating) only. A draft damper may be required to obtain the guaranteed emissions at turndown.
3. Furnace meets (min.) construction requirements for furnace sidewall integrity and seals at the drums and front wall. CO emission stated above is provided furnace leakage (bypassing of flue gas) does not contribute more than .015 lb/MMBTU to the total CO emissions.
4. Emission guarantees exclude background emissions present in the air or fuel used for combustion.
5. NBW field service must do the initial burner adjustments and must be present during testing for optimization of the equipment supplied.
6. Emission testing must be conducted within the warranty period. Upon obtaining the guaranteed emissions, as described above, the equipment shall be considered accepted.

MECHANICAL INSTALLATION

1. Install steel and hoist system to allow for installation and removal of fan and motor.
2. The existing burner wind box with all fuel valves will be disconnected and removed from the front of the boiler.
3. All these items will be moved out from the operating floor and placed in scrap hoppers provided by the customer.
4. The existing air duct connecting the existing FD fan to the burner wind box will be completely removed and placed in the customer supplied scrap hoppers.
5. We will remove all the refractory and insulation on the front wall of the boiler. The removed material will be placed in roller hoppers moved to the roll up doorway lowered to the ground and dumped into disposal hoppers provided by Bunge.
6. The new burner with skid mounted fuel trains will be unloaded moved on to the operating floor.
7. The Zeeco E-style wind box and burner assembly will be moved to the front of the English boiler.
8. The complete wind box will be set in place and aligned on the front of the boiler.
9. The entire wind box will be seal welded to the boiler front plate.
10. The new Arrangement 4 FD fan will be set and placed on top of the new wind box on the front of the boiler.

11. On the front wall there will be two (2) layers of 2,800 mineral wool insulating board laid against the existing steel boiler front plate and fastened in place with stainless steel clips.
12. New refractory brick work will be laid up against this new insulation board on the entire front wall of the boiler.
13. The new Zeeco refractory throat will be installed and sealed to the refractory front wall of the boiler.
14. The furnace access door will be framed with 2" x 12" x 36" square edge tile and sealed around the perimeter with 3,000 deg. castable cement.
15. The furnace access door will be formed and poured with new refractory.
16. The fuel skid assembly will be located near the burner at an agreed upon location and fastened to the operating floor.
17. We will install the loose items, PRV valve, strainer, and shutoff valve.
18. The existing natural gas line will be re-routed and connected to the new fuel skid assembly.
19. The natural gas vent piping will be routed and connected to the existing vent lines.
20. The steam pressure switches will be connected to the steam drum.
21. We will provide start-up tech for 10 days to start-up and test the boiler after the outage is completed and 5 days to provide assistance to the electrical contractor for 5 days.
22. We will leave the premises in a clean, broom swept condition.

WORK BY OTHERS

- We have not included any electrical wiring for the new burner and fuel train.
- VFD is not included and will be supplied by the customer.
- No insulation is included.
- Hoppers to be provided by the customer for all scrap material to be disposed of.

PRICE STRUCTURE PER BOILER X1

Budget price per the above scope of work **\$997,619.00**

STARTUP SERVICE AND TRAINING

We will provide the startup, system calibration and operator training for this new control system.

This service is offered on a per diem basis at the rate of **\$4,150.00** per 8-hour day, plus travel and normal living expenses. **10 days is included in the base bid.** Anything needed beyond 5 days per boiler will be charged at a per day rate.

SCHEDULE

Delivery of Zeeco Burner	32 weeks
Delivery of the FD Fan	32 weeks

PAYMENT TERMS

15% Invoiced upon receipt of order
35% Invoiced upon approval of drawings
25% upon delivery of all equipment
25% upon completion of project

WARRANTY

The equipment furnished and the mechanical installation is fully warranted for a period of one (1) year effective from date of startup.

MATERIAL PRICING

Due to the uncertainty of the commodities market, we are being faced with today may result in some modifications to our material costs. We have based our estimate on the current price index. All our suppliers are in the same position and have stated that in their quotes to us. We must advise you that there may be some changes in our costs due to this condition.

STEEL PRICES AND AVAILABILITY

Market prices for steel materials are unstable due to a variety of factors including, but not limited to, cost increases for iron ore, steel scrap, coke, nickel, chromium, vanadium and other metals and alloys, as well as fuel prices and currency exchange fluctuations. Contractor's Proposal Price is based on current availability and prices of steel products in effect as of the date of this Proposal. If, prior to acceptance of a Contract, Contractor determines that its schedule or price will be adversely affected by this instability or from the imposition of restrictions on steel imports or tariffs by the U.S. government, Contractor reserves the right to amend its Proposal for the Contract.

FREIGHT

Transportation costs are unstable due to global demand and regulatory mandates which have affected all modes of transportation including rail, water (including, but not limited to, ocean vessels), air and trucking. Therefore, Contractor's Proposal is based on transportation costs currently known and the availability of transportation resources. If, prior to acceptance of a Contract, Contractor determines that its schedule or price will be adversely affected by such instability or availability, Contractor reserves the right to amend its Proposal for the Contract.

Yours Very Truly,
NBW, Inc.



Burgess "Burg" M. Holt
216-854-5348
bmholt@nbwinc.com

Attachment 4

Source Test Report (April 2026) for Boilers B008 and B009

Source Test Report for 2026 In-House Engineering Testing

Howmet Aerospace Inc.
Cleveland, Ohio

98.8 MMBtu/hr Natural Gas Fired Boilers (B008 and B009)

Prepared for: Howmet Aerospace Inc.
 1600 Harvard Avenue
 Cleveland, OH 44105

Prepared by: Onterris Air Quality Services, LLC
 10060 Brecksville Road
 Cleveland, OH 44114

Document Number: NE011AS-067458-RT-2711

Test Date: April 23-24, 2026

Submittal Date: May 1, 2026

Review and Certification

April 23-24, 2026 In-House Engineering Test

Howmet Aerospace Inc. - Cleveland, Ohio

98.8 MMBtu/hr Natural Gas Fired Boilers (B008 and B009)

All work, calculations, and other activities and tasks performed and presented in this document were carried out by me or under my direction and supervision. I hereby certify that, to the best of my knowledge, Onterris operated in conformance with the requirements of the Onterris Quality Management System and ASTM D7036-04 during this test project.

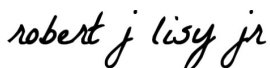


05 / 01 / 2026

Jeremiah Hicks
Account Manager

Date

I have reviewed, technically and editorially, details, calculations, results, conclusions, and other appropriate written materials contained herein. I hereby certify that, to the best of my knowledge, the presented material is authentic, accurate, and conforms to the requirements of the Onterris Quality Management System and ASTM D7036-04.



05 / 01 / 2026

Robert J. Lisy Jr.
District Manager

Date

Disclaimer

Onterris Air Quality Services (Onterris) certifies to Howmet Aerospace Inc (the Client) that the conclusions in this report are the professional opinions of Onterris at the time of the report and concerning the scope described in the report. The opinions are based on the site conditions observed on the date set out in the report and information obtained during the performance of the scope and do not contemplate subsequent changes in site conditions or information or changes in applicable law or standards subsequent to the date of the report. Onterris has exercised a customary level of skill, care, and diligence in using information received from the Client and/or third parties in the preparation of the report, however, assumes no responsibility or liability for the consequences of any error or omission contained in such information. This report was prepared solely for the use of the Client in relation to the specific scope, location, and purpose for which Onterris was retained and is not intended to be used for any variation or extension of the scope or any other project or purpose. Any other use or reliance on the report by the Client or any use or reliance by any third party without the prior express written consent of Onterris is at the sole risk and responsibility of the user and Onterris makes no representation or warranty with respect to any unauthorized use and expressly disclaims any legal duty of care to any such person. Neither Onterris nor its affiliates are responsible for damages, losses, fines, penalties, or other harm incurred by such unauthorized user as a result of decisions made or actions taken based on this report. This report may not be read or reproduced except in its entirety.

Table of Contents

1	Introduction	5
1.1	Summary of Test Program	5
1.2	Key Personnel.....	7
2	Plant and Sampling Location Descriptions	8
2.1	Process Description, Operation, and Control Equipment	8
2.2	Flue Gas Sampling Locations.....	8
2.3	Operating Conditions and Process Data	8
3	Sampling and Analytical Procedures.....	9
3.1	Test Methods	9
3.1.1	EPA Method 3A.....	9
3.1.2	EPA Method 7E.....	9
3.1.3	EPA Method 19	10
3.2	Process Test Methods.....	10
4	Test Discussion and Results.....	11
4.1	Field Test Deviations and Exceptions.....	11
5	Internal QA/QC Activities	13
5.1	QA/QC Audits	13
5.2	QA/QC Discussion	13
5.3	Quality Statement.....	13

List of Figures

Figure 3-1	EPA Methods 3A (O ₂) and 7E Sampling Train.....	10
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List of Tables

Table 1-1	Summary of Test Program.....	5
Table 1-2	Summary of Average Results – B008 and B008 Exhaust Stacks	6
Table 1-3	Test Personnel and Observers	7
Table 2-1	Sampling Locations.....	8
Table 4-1	NO _x Emission Results – B008 Exhaust Stack	12
Table 4-2	NO _x Emission Results – B009 Exhaust Stack	12



Appendices

Appendix A	Field Data and Calculations	14
Appendix A1	Sampling Locations	15
Appendix A2	B008 Exhaust Stack Data Sheets	19
Appendix A3	B009 Exhaust Stack Data Sheets	25
Appendix A4	B008 Instrumental Test Method Data	31
Appendix A5	B009 Instrumental Test Method Data	37
Appendix A6	Example Calculations	43
Appendix B	Facility Process Data	46
Appendix C	Quality Assurance / Quality Control	48
Appendix C1	Units and Abbreviations	49
Appendix C2	Instrumental Test Method QA/QC Data	59
Appendix C3	Accreditation Information / Certifications	75

1 Introduction

1.1 Summary of Test Program

Howmet Aerospace Inc. contracted Onterris Air Quality Services, LLC to perform an In-House engineering emissions test program on two 98.8 MMBtu/hr Natural Gas-Fired Boilers (B008 and B009) at Howmet Aerospace Inc. (Facility ID No. 13-18-17-0314) located in Cleveland, Ohio. The tests were conducted to provide Howmet Aerospace Inc. with information for internal use.

The specific objectives were to:

- Measure emissions of nitrogen oxide (NO_x), (lb/MMBtu) (as NO₂), at the B008 Exhaust Stack and B009 Exhaust Stack
- Conduct the test program with a focus on safety

Onterris performed the tests to measure the emission parameters listed in Table 1-1.

Table 1-1 Summary of Test Program

Test Dates	Unit ID / Source Name	Activity / Parameters	Test Methods	No. of Runs	Duration (Minutes)
4/23/2026	B008 Exhaust Stack	O ₂	EPA M3A	3	60
		NO _x	EPA M7E EPA M19	3	60
4/24/2026	B009 Exhaust Stack	O ₂	EPA M3A	3	60
		NO _x	EPA M7E EPA M19	3	60

To simplify this report, a list of Units and Abbreviations is included in Appendix C1. Throughout this report, chemical nomenclature, acronyms, and reporting units are not defined. Please refer to the list for specific details.

This report presents the test results and supporting data, descriptions of the testing procedures, descriptions of the facility and sampling locations, and a summary of the quality assurance procedures used by Onterris. The average emission test results are summarized and compared to their respective permit limits in Table 1-2. Detailed results for individual test runs can be found in Section 4.0. All supporting data can be found in the appendices.

The testing was conducted by the Onterris personnel listed in Table 1-3.

Table 1-2 Summary of Average Results – B008 and B008 Exhaust Stacks
April 23-24, 2026

Parameter/Units	Average Results	Emission Limits
Nitrogen Oxides (NO_x) – B008 Exhaust Stack		
ppmvd	99.5	--
lb/MMBtu	0.13	--
Nitrogen Oxides (NO_x) – B009 Exhaust Stack		
ppmvd	120.5	--
lb/MMBtu	0.15	--

1.2 Key Personnel

A list of project participants is included below:

Facility Information

Source Location: Howmet Aerospace Inc.
1600 Harvard Avenue
Cleveland, OH 44105

Project Contact: Jonah Ross
Role: Environmental Engineer
Company: Howmet Aerospace Inc
Telephone: 412-418-5338
Email: jonah.ross@howmet.com

Testing Company Information

Testing Firm:	Onterris Air Quality Services	
Contact:	Jeremiah Hicks	Robert J. Lisy, Jr.
Title:	Account Manager	District Manager
Telephone:	440-340-8189	440-262-3760
Email:	jhicks@onterris.com	rlisy@onterris.com

Test personnel and observers are summarized in Table 1-3.

Table 1-3 Test Personnel and Observers

Name	Affiliation	Role/Responsibility
Cederic Ebbeler	Onterris	Senior Field Technician, QI
Anthony Kemer	Onterris	Field Technician
Jonah Ross	Howmet Aerospace Inc.	Test Coordinator

2 Plant and Sampling Location Descriptions

2.1 Process Description, Operation, and Control Equipment

Howmet Aerospace operates two Nebraska Boiler Company - Model NS-F-73SH 98.8 MMBtu/hr Natural Gas-Fired Boilers (B008 and B009). Each boiler is equipped with Lower NO_x burners to reduce emissions.

2.2 Flue Gas Sampling Locations

Information regarding the sampling location(s) is presented in Table 2-1.

Table 2-1 Sampling Locations

Sampling Location	Stack Inside Diameter (in.)	Distance from Nearest Disturbance		Number of Traverse Points
		Downstream EPA "B" (in./dia.)	Upstream EPA "A" (in./dia.)	
B008 Exhaust Stack	41.8	150.0/3.6	96.0/2.3	Gaseous: 3
B009 Exhaust Stack	41.6	150.0/3.6	96.0/2.3	Gaseous: 3

The sample locations were verified in the field to conform to EPA Method 1. See Appendix A1 for more information.

2.3 Operating Conditions and Process Data

Emission tests were performed while the source/units and air pollution control devices were operating normally.

Plant personnel were responsible for establishing the test conditions and collecting all applicable unit-operating data. Data collected includes the following parameters:

- Natural gas usage, cfm

3 Sampling and Analytical Procedures

3.1 Test Methods

The test methods for this test program have been presented in Table 1-1. Additional information regarding specific applications or modifications to standard procedures is presented below.

3.1.1 EPA Method 3A - Determination of Oxygen and Carbon Dioxide in Emissions from Stationary Sources (Instrumental Analyzer Procedure)

EPA Method 3A is an instrumental test method used to measure the concentration of O₂ and CO₂ in stack gas. The effluent gas is continuously or intermittently sampled and conveyed to analyzers that measure the concentration of O₂ and CO₂. The performance requirements of the method must be met to validate data.

Pertinent information regarding the performance of the method is presented below:

- Method Options:
 - Calibration span value is 22.05% O₂
- Method Exceptions:
 - None

The typical sampling system is detailed in Figure 3-1.

3.1.2 EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure)

EPA Method 7E is an instrumental test method used to continuously measure emissions of NO_x as NO₂. Conditioned gas is sent to a chemiluminescent analyzer to measure the concentration of NO_x. NO and NO₂ can be measured separately or simultaneously together but, for the purposes of this method, NO_x is the sum of NO and NO₂. The performance requirements of the method must be met to validate the data.

Pertinent information regarding the performance of the method is presented below:

- Method Options:
 - Calibration span value is 200 ppmv
- Method Exceptions:
 - None

The typical sampling system is detailed in Figure 3-1.

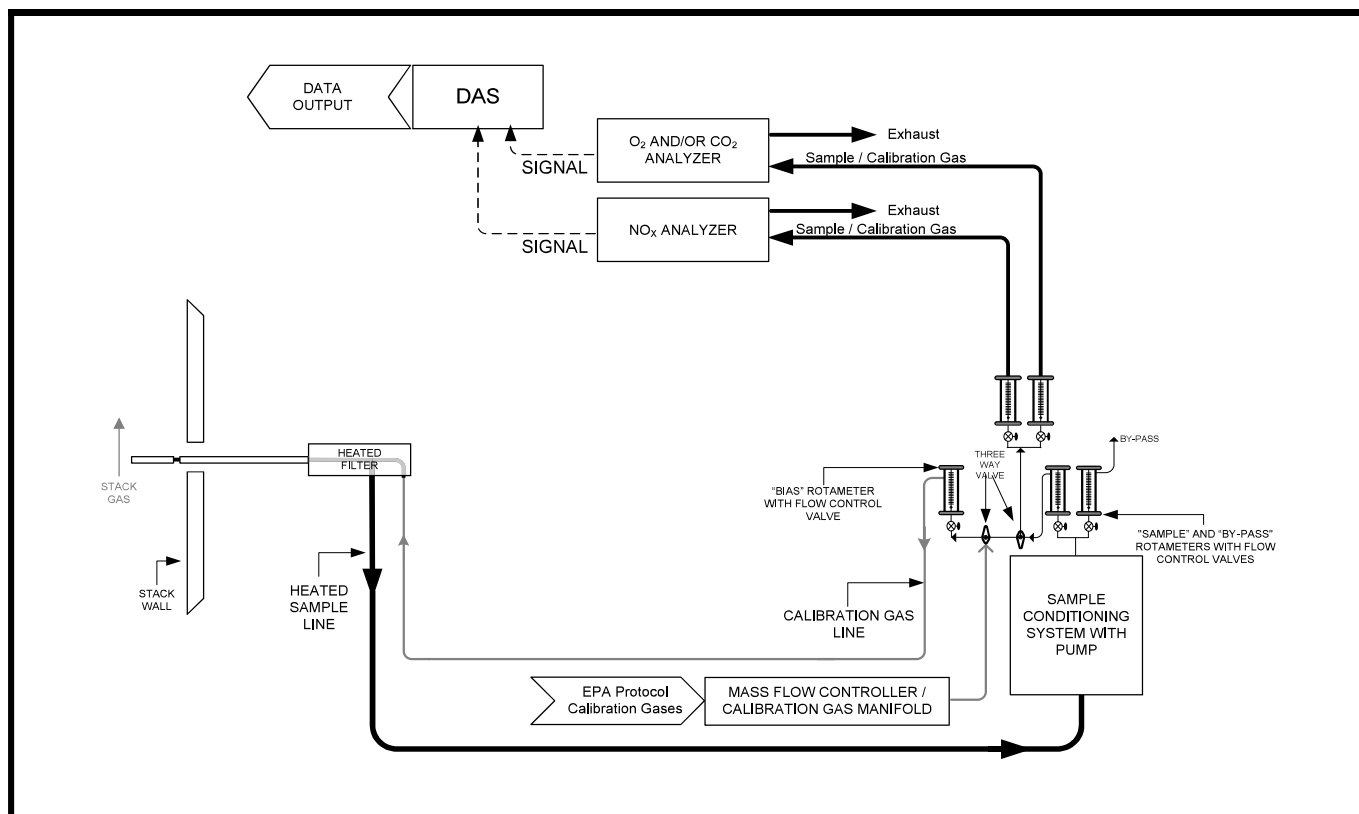


Figure 3-1 EPA Methods 3A (O₂) and 7E Sampling Train

3.1.3 EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates

EPA Method 19 is used to calculate mass emission rates in units of lb/MMBtu. EPA Method 19, Table 19-2 contains a list of assigned fuel factors for different types of fuels, which can be used for these calculations.

Pertinent information regarding the performance of the method is presented below:

- Method Options:
 - F factor is the oxygen-based F factor, dry basis (dscf/MMBtu) (Fd)
- Method Exceptions
 - None

3.2 Process Test Methods

The test plan did not require that process samples be collected during this test program; therefore, no process sample data are presented in this test report.

4 Test Discussion and Results

4.1 Field Test Deviations and Exceptions

No field deviations or exceptions from the test plan or test methods occurred during this test program. Presentation of Results

The average results are compared to the permit limits in Table 1-2. The results of individual test runs performed are presented in Tables 4-1 and 4-2. Emissions are reported in units consistent with those in the applicable regulations or requirements. Additional information is included in the appendices as presented in the Table of Contents.

Table 4-1 NO_x Emission Results – B008 Exhaust Stack

Parameter/Units	Run 1	Run 2	Run 3	Average
Date	4/23/2026	4/23/2026	4/23/2026	--
Time	16:45-17:45	18:00-19:00	19:15-20:15	--
Process Data ¹				
natural gas usage, cfm	838	836	847	840
Sampling & Flue Gas Parameters				
sample duration, minutes	60	60	60	--
O ₂ , % volume dry	3.69	3.65	3.66	3.66
Nitrogen Oxides (NO_x)				
ppmvd	102.3	98.6	97.5	99.5
lb/MMBtu (as NO ₂)	0.13	0.12	0.12	0.13

¹ Facility process data was recorded by Onterris personnel

Table 4-2 NO_x Emission Results – B009 Exhaust Stack

Parameter/Units	Run 1	Run 2	Run 3	Average
Date	4/24/2026	4/24/2026	4/24/2026	--
Time	12:30-13:30	13:45-14:45	15:00-16:00	--
Process Data ¹				
natural gas usage, cfm	827	838	838	834
Sampling & Flue Gas Parameters				
sample duration, minutes	60	60	60	--
O ₂ , % volume dry	3.11	3.07	3.08	3.09
Nitrogen Oxides (NO_x)				
ppmvd	120.5	121.1	122.1	121.2
lb/MMBtu (as NO ₂)	0.15	0.15	0.15	0.15

¹ Facility process data was recorded by Onterris personnel

5 Internal QA/QC Activities

5.1 QA/QC Audits

EPA Method 3A and 7E calibration audits were all within the measurement system performance specifications for the calibration drift checks, system calibration bias checks, and calibration error checks.

The NO₂ to NO converter efficiency check of the analyzer was conducted per the procedures in EPA Method 7E, Section 8.2.4. The conversion efficiency met the criteria.

An EPA Method 205 field evaluation of the calibration gas dilution system was conducted. The dilution accuracy and precision QA specifications were met.

5.2 QA/QC Discussion

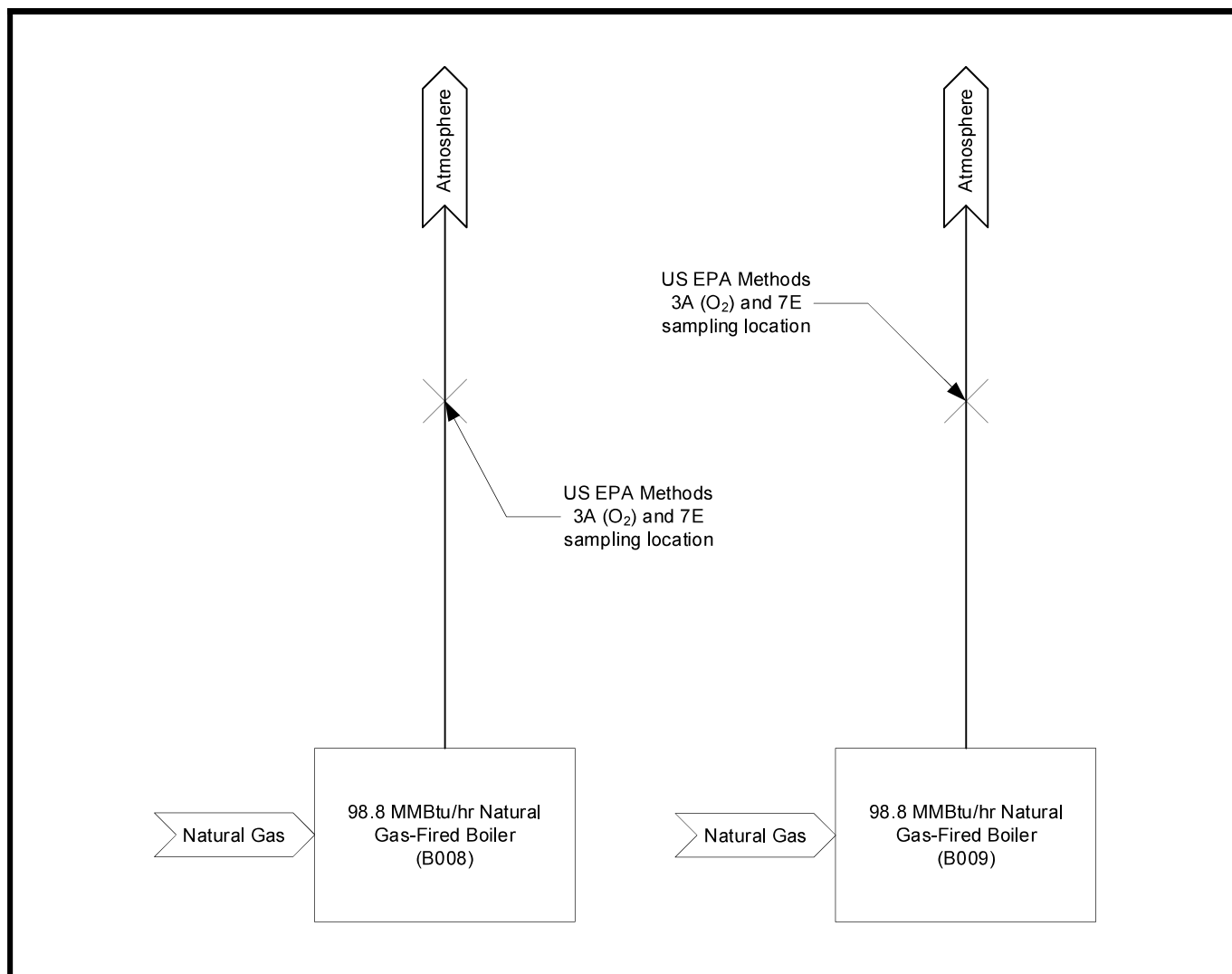
All QA/QC criteria were met during this test program.

5.3 Quality Statement

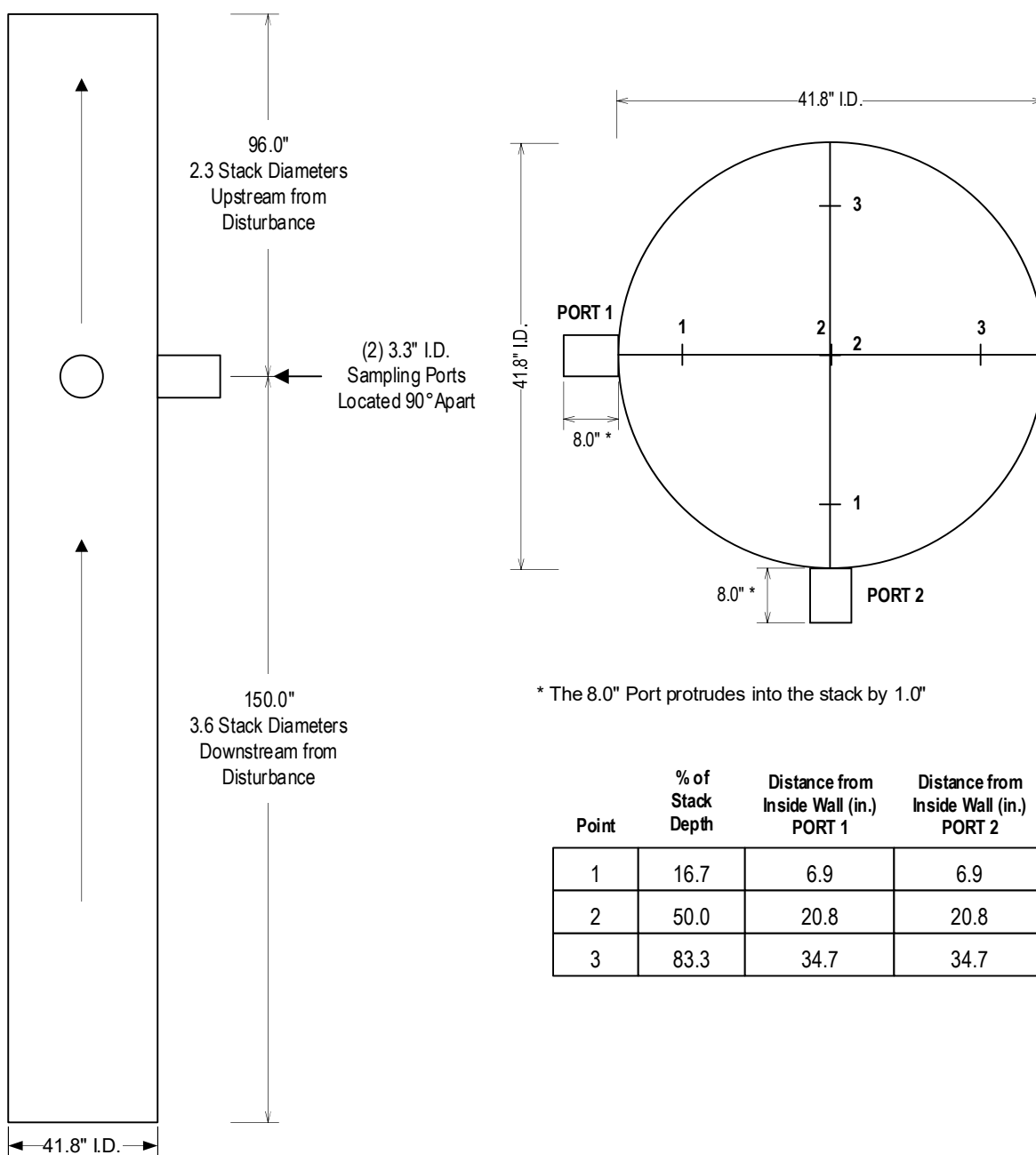
Onterris is qualified to conduct this test program and has established a quality management system that led to accreditation with ASTM Standard D7036-04 (Standard Practice for Competence of Air Emission Testing Bodies). Onterris participates in annual functional assessments for conformance with D7036-04 which are conducted by the American Association for Laboratory Accreditation (A2LA). All testing performed by Onterris is supervised on site by at least one Qualified Individual (QI) as defined in D7036-04 Section 8.3.2. Data quality objectives for estimating measurement uncertainty within the documented limits in the test methods are met by using approved test protocols for each project as defined in D7036-04 Sections 7.2.1 and 12.10. Additional quality assurance information is included in the report appendices. The content of this report is modeled after the EPA Emission Measurement Center Guideline Document (GD-043).

Appendix A Field Data and Calculations

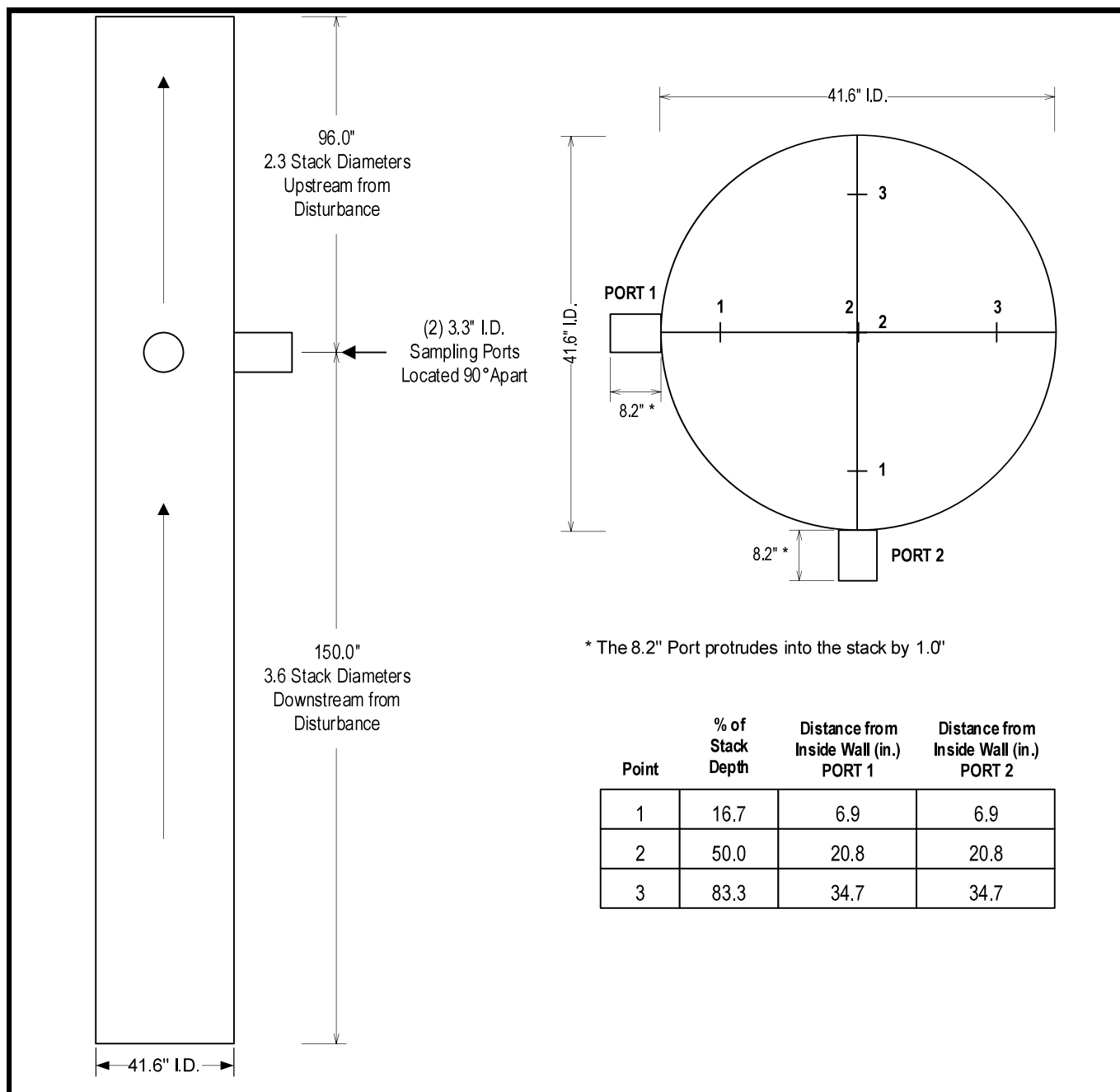
Appendix A1 Sampling Locations



B008 and B009 Sampling Location/Process Flow Schematic



B008 CEMS Traverse Point Schematic*



B009 CEMS Traverse Point Schematic*

Appendix A2 B008 Exhaust Stack Data Sheets

Test Data

Number of Test Runs	3			
Number of Traverse Points	3			
	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Total Sampling Run Time, Theta, min	60	60	60	60
Test Run Start Time, mm/dd/yyyy hh:mm	4/23/2026 16:45	4/23/2026 18:00	4/23/2026 19:15	
Test Run Stop Time, mm/dd/yyyy hh:mm	4/23/2026 17:45	4/23/2026 19:00	4/23/2026 20:15	
Stack Cross-Sectional Diameter 1, circular , in	41.8	41.8	41.8	41.8
Stack Cross-Sectional Diameter 2, circular , in	41.8	41.8	41.8	41.8
Elevation Difference Between Location/Site and Meter Box, ft	0.00	0.00	0.00	0.00
Elevation Difference Between Location/Site and Sampling Ports, ft	30.00	30.00	30.00	30.00
Air Percent by Volume Oxygen in Stack Gas, %-dry	3.71	3.66	3.66	3.68

HEAT INPUT

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Published / Provided F-Factor, Fd, dscf/MMBtu	8710	8710	8710	8710

Test Data - EPA Method 3A (O₂)

Number of Concentration Runs

Analyzer Calibration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Actual Concentration of the Mid-Level Calibration Gas, %	11.00	11.00	11.00	11.00
Actual Concentration of the High-Level Calibration Gas, %	22.05	22.05	22.05	22.05
Analyzer Span During Test Run, %	22.05	22.05	22.05	22.05
Calibration Gas QA	GOOD	GOOD	GOOD	
Analyzer Calibration Response for Zero Gas, %	0.03	0.03	0.03	0.03
Analyzer Calibration Response for Mid-Level Gas, %	11.04	11.04	11.04	11.04
Analyzer Calibration Response for High Level Gas, %	22.02	22.02	22.02	22.02
Initial System Calibration Response for Zero Gas, %	0.07	0.09	0.07	0.08
Initial System Calibration Response for Upscale Gas, %	10.92	10.91	10.85	10.89
Final System Calibration Response for Zero Gas, %	0.09	0.07	0.08	0.08
Final System Calibration Response for Upscale Gas, %	10.91	10.85	10.87	10.88

Analyzer Calibration QA

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Initial System Calibration Bias for Zero Gas, % of Span	0.18	0.27	0.18	0.21
Initial System Calibration Bias for Upscale Gas, % of Span	-0.54	-0.59	-0.86	-0.67
Final System Calibration Bias for Zero Gas, % of Span	0.27	0.18	0.23	0.23
Final System Calibration Bias for Upscale Gas, % of Span	-0.59	-0.86	-0.77	-0.74
System Drift for Zero Gas, % of Span	0.09	-0.09	0.05	0.02
System Drift for Upscale Gas, % of Span	-0.05	-0.27	0.09	-0.08
Analyzer Calibration Error for Zero Gas, % of Span	0.14	0.14	0.14	0.14
Analyzer Calibration Error for Mid-Level Gas, % of Span	0.18	0.18	0.18	0.18
Analyzer Calibration Error for High-Level Gas, % of Span	-0.14	-0.14	-0.14	-0.14

CONCENTRATION CALCULATIONS - DRY SYSTEM

Calculate the Average Effluent Oxygen O₂ Concentration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Average O ₂ Concentration Indicated by Gas Analyzer, dry basis, %-dry	3.71	3.66	3.66	3.68
Average of Initial and Final System Calibration Bias Check Responses for the Zero Gas, %	0.08	0.08	0.08	0.08
Average of Initial and Final System Calibration Bias Check Responses for the Upscale Calibration Gas, %	10.92	10.88	10.86	10.89
Average Effluent O ₂ Concentration, dry basis, %-dry	3.69	3.65	3.66	3.66

Test Data - EPA Method 7E

Analyzer Calibration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Actual Concentration of the Mid-Level Calibration Gas, ppmvd	100	100	100	100
Actual Concentration of the High-Level Calibration Gas, ppmvd	200	200	200	200
Analyzer Span During Test Run, ppmvd	200	200	200	200
Calibration Gas QA	GOOD	GOOD	GOOD	
Analyzer Calibration Response for Zero Gas, ppmvd	0.18	0.18	0.18	0.18
Analyzer Calibration Response for Mid-Level Gas, ppmvd	98.16	98.16	98.16	98.16
Analyzer Calibration Response for High Level Gas, ppmvd	199.21	199.21	199.21	199.21
Initial System Calibration Response for Zero Gas, ppmvd	0.68	0.88	0.71	0.76
Initial System Calibration Response for Upscale Gas, ppmvd	95.33	97.37	97.97	96.89
Final System Calibration Response for Zero Gas, ppmvd	0.88	0.71	0.82	0.80
Final System Calibration Response for Upscale Gas, ppmvd	97.37	97.97	98.02	97.79

Analyzer Calibration QA

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Actual Concentration of the Nitrogen Dioxide (NO ₂) Calibration Gas, ppmv	50.11	50.11	50.11	50.11
Analyzer Response to Nitrogen Dioxide (NO ₂) Calibration Gas, ppmv	46.86	46.86	46.86	46.86
Analyzer NO ₂ to NO Converter Efficiency	93.51	93.51	93.51	93.51
Initial System Calibration Bias for Zero Gas, % of Span	0.25	0.35	0.27	0.29
Initial System Calibration Bias for Upscale Gas, % of Span	-1.42	-0.39	-0.09	-0.63
Final System Calibration Bias for Zero Gas, % of Span	0.35	0.27	0.32	0.31
Final System Calibration Bias for Upscale Gas, % of Span	-0.39	-0.09	-0.07	-0.19
System Drift for Zero Gas, % of Span	0.10	-0.09	0.06	0.02
System Drift for Upscale Gas, % of Span	1.02	0.30	0.02	0.45
Analyzer Calibration Error for Zero Gas, % of Span	0.09	0.09	0.09	0.09
Analyzer Calibration Error for Mid-Level Gas, % of Span	-0.92	-0.92	-0.92	-0.92
Analyzer Calibration Error for High-Level Gas, % of Span	-0.39	-0.39	-0.39	-0.39

DETAILED RESULTS - DRY SYSTEM

Emission Results

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Average NO _x Mass Emission Rate (as NO ₂), (lb/MMBtu)	0.129	0.124	0.123	0.13

CONCENTRATION CALCULATIONS - DRY SYSTEM

Average Nitrogen Oxides (NO_x) Concentration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Average NO _x Concentration Indicated by Gas Analyzer, ppmvd	98.57	96.32	95.58	96.82
Average of Initial and Final System Calibration Bias Check Responses for the Zero Gas, ppmvd	0.78	0.80	0.77	0.78
Average of Initial and Final System Calibration Bias Check Responses for the Upscale Calibration Gas, ppmvd	96.35	97.67	98.00	97.34
Average NO _x Concentration, ppmvd	102.32	98.61	97.52	99.48

EPA Method 1 (Round/Rectangular) - Stack/Duct Dimensions

Company: Howmet

Project ID: PROJ- 067458

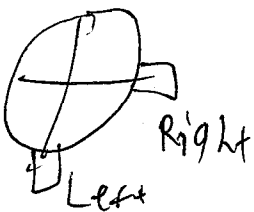
Location: B008

Technician: CE

Date: 4-23-26

	Port 1	Port 2	Port 3	Port 4	Port 5
Relative Location ¹	<u>Left</u>	<u>Right</u>			
From Far Inside Wall to Outside of Port (in.) ²	<u>48.8</u>	<u>48.8</u>			
Nipple Length and/or Wall Thickness (in.) ³	<u>8.0</u>	<u>8.0</u>			
Nipple Protrusion (in.) ⁴	<u>1.0</u>	<u>1.0</u>	<u>41.8</u>		
Stack/Duct Depth (Inner Dimension) (in.) ⁵	<u>40.8</u>	<u>40.8</u>			
Port Hole Inner Diameter (in.) ⁶	<u>4</u>	<u>4</u>			
Measured Particulate Build-up (in.) ⁷	<u>-</u>	<u>-</u>			
Stack/Duct Width (inner), if Rectangular (in.)				Port 6	Port 7
Number of Ports Traversed	<u>2</u>				
Direction of Flow and Stack Orientation:	<u>VP / Vertical</u>				
Sample Port Access	<u>Roof</u>				
Elevation of Meter Box from Ground Level (ft)	<u>-</u>				
Elevation of Ports from Ground Level (ft)	<u>30</u>				
Isokinetic Sample (Yes / No)	<u>no</u>				
Elevation of Barometer from Ground Level (ft)	<u>-</u>				
Stack Outer Dimensions (in.)	<u>128</u>				
Distance Upstream from Flow Disturbance (in.)	<u>96</u>				
Disturbance Type: <u>Atmospheric</u>					
Distance Downstream from Flow Disturbance (in.)	<u>150</u>				
Disturbance Type: <u>Bend</u>					

* CE 4/28/26

Stack/Duct Cross Section Schematic	Stack/Duct Flow Direction Schematic
	

QA/QC Check: Completeness [☒] Accuracy [☒] Specifications [☒]

Checked by: CE

001AS-QMS-TM-62

Onterris Air Quality Services, LLC

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011AS-Manual Methods-Effective-04.22.26&[Tab]

CEMS Traverse Point Determination - B008

Relative Port Location	1	2
From Far Wall to Outside of Port (in.)	48.8	48.8
Nipple Length or Wall Thickness (in.)	8.0	8.0
Port Protrusion Length (opt) (in.)	1.0	1.0
Depth of Stack or Duct (in.)	41.8	41.8
Stack or Duct Type	Circular	
Port Hole Inner Diameter (in.)	3.3	
Stack or Duct Width (If Rectangular) (in.)		
Stack Outer Circumference (in.)		
Number of Ports Traversed	2	
Elevation of Meter Box from Ground Level (ft)		
Elevation of Ports from Ground Level (ft)		
Stack Build-up (in.)	0.0	
Stack Cross-Sectional Diameter 1 (in)	41.8	
Stack Cross-Sectional Diameter 2 (in)	41.8	

"Vertical" or "Horizontal" Flow	Vertical
Direction of Flow	Up
"Velocity" or "Isokinetic" Traverse	Velocity

Port Distance Upstream from Flow Disturbance (in.)	96.0
Diameters Upstream from Flow Disturbance (³ 0.5 De)	2.3
Minimum Traverse Points Needed for a Velocity Traverse *	12
Minimum Traverse Points Needed for a Isokinetic Traverse *	12

Port Distance Downstream from Flow Disturbance (in.)	150.0
Diameters Downstream from Flow Disturbance (³ 2.0 De)	3.6
Minimum Traverse Points Needed for a Velocity Traverse *	16
Minimum Traverse Points Needed for a Isokinetic Traverse *	24

Minimum Traverse Points per Method 1	16
Number of Traverse Points for this Circular Stack or Duct	6
Point Override	6

Duct Area - in² 1372.28
Duct Area - ft² 9.5297

Note:

Add nipple protrusion length to Point 1 only.

Actual nipple length = (length - protrusion)

Relocate to a distance equal to the inside diameter of the nozzle being used or to the above minimum distances, whichever is larger.

This Stack having a diameter greater than 24-inches, shall have no traverse points located within 1.0-inch of the stack wall.

verified on 4/23/2026 by: CE

Port	Point	% of Duct Depth	Dist. From Inside Wall (Decimal)	Dist. From Outside Wall (Decimal)
1	1	16.7	7.0	14.0
1	2	50.0	20.9	27.9
1	3	83.3	34.8	41.8
2	1	16.7	7.0	14.0
2	2	50.0	20.9	27.9
2	3	83.3	34.8	41.8

Appendix A3 B009 Exhaust Stack Data Sheets

Test Data

Number of Test Runs	3			
Number of Traverse Points	3			
	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Total Sampling Run Time, Theta, min	60	60	60	60
Test Run Start Time, mm/dd/yyyy hh:mm	4/24/2025 12:30	4/24/2025 13:45	4/24/2025 15:00	
Test Run Stop Time, mm/dd/yyyy hh:mm	4/24/2025 13:30	4/24/2025 14:45	4/24/2025 16:00	
Stack Cross-Sectional Diameter 1, circular , in	41.60	41.60	41.60	41.60
Stack Cross-Sectional Diameter 2, circular , in	41.60	41.60	41.60	41.60
Air Percent by Volume Oxygen in Stack Gas, %-dry	3.17	3.09	3.10	3.12
Air Percent by Volume Nitrogen in Stack Gas, %-dry	96.83	96.91	96.90	96.88

HEAT INPUT

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Published / Provided F-Factor, Fd, dscf/MMBtu	8710	8710	8710	8710

Test Data - EPA Method 3A (O₂)

Number of Concentration Runs

Analyzer Calibration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Actual Concentration of the Mid-Level Calibration Gas, %	11.00	11.00	11.00	11.00
Actual Concentration of the High-Level Calibration Gas, %	22.05	22.05	22.05	22.05
Analyzer Span During Test Run, %	22.05	22.05	22.05	22.05
Calibration Gas QA	GOOD	GOOD	GOOD	
Analyzer Calibration Response for Zero Gas, %	0.09	0.09	0.09	0.09
Analyzer Calibration Response for Mid-Level Gas, %	11.09	11.09	11.09	11.09
Analyzer Calibration Response for High Level Gas, %	22.02	22.02	22.02	22.02
Initial System Calibration Response for Zero Gas, %	0.14	0.08	0.08	0.10
Initial System Calibration Response for Upscale Gas, %	10.98	10.87	10.86	10.90
Final System Calibration Response for Zero Gas, %	0.08	0.08	0.07	0.08
Final System Calibration Response for Upscale Gas, %	10.87	10.86	10.88	10.87

Analyzer Calibration QA

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Initial System Calibration Bias for Zero Gas, % of Span	0.23	-0.05	-0.05	0.05
Initial System Calibration Bias for Upscale Gas, % of Span	-0.50	-1.00	-1.04	-0.85
Final System Calibration Bias for Zero Gas, % of Span	-0.05	-0.05	-0.09	-0.06
Final System Calibration Bias for Upscale Gas, % of Span	-1.00	-1.04	-0.95	-1.00
System Drift for Zero Gas, % of Span	-0.27	0.00	-0.05	-0.11
System Drift for Upscale Gas, % of Span	-0.50	-0.05	0.09	-0.15
Analyzer Calibration Error for Zero Gas, % of Span	0.41	0.41	0.41	0.41
Analyzer Calibration Error for Mid-Level Gas, % of Span	0.41	0.41	0.41	0.41
Analyzer Calibration Error for High-Level Gas, % of Span	-0.14	-0.14	-0.14	-0.14

CONCENTRATION CALCULATIONS - DRY SYSTEM

Calculate the Average Effluent Oxygen O₂ Concentration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Average O ₂ Concentration Indicated by Gas Analyzer, dry basis, %-dry	3.17	3.09	3.10	3.12
Average of Initial and Final System Calibration Bias Check Responses for the Zero Gas, %	0.11	0.08	0.08	0.09
Average of Initial and Final System Calibration Bias Check Responses for the Upscale Calibration Gas, %	10.93	10.87	10.87	10.89
Average Effluent O ₂ Concentration, dry basis, %-dry	3.11	3.07	3.08	3.09

Test Data - EPA Method 7E

Analyzer Calibration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Actual Concentration of the Mid-Level Calibration Gas, ppmvd	100	100	100	100
Actual Concentration of the High-Level Calibration Gas, ppmvd	200	200	200	200
Analyzer Span During Test Run, ppmvd	200	200	200	200
Calibration Gas QA	GOOD	GOOD	GOOD	
Analyzer Calibration Response for Zero Gas, ppmvd	0.16	0.16	0.16	0.16
Analyzer Calibration Response for Mid-Level Gas, ppmvd	97.70	97.70	97.70	97.70
Analyzer Calibration Response for High Level Gas, ppmvd	199.23	199.23	199.23	199.23
Initial System Calibration Response for Zero Gas, ppmvd	0.37	0.90	0.88	0.72
Initial System Calibration Response for Upscale Gas, ppmvd	96.21	95.40	96.32	95.98
Final System Calibration Response for Zero Gas, ppmvd	0.90	0.88	0.78	0.85
Final System Calibration Response for Upscale Gas, ppmvd	95.40	96.32	96.56	96.09

Analyzer Calibration QA

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Actual Concentration of the Nitrogen Dioxide (NO ₂) Calibration Gas, ppmv	50.11	50.11	50.11	50.11
Analyzer Response to Nitrogen Dioxide (NO ₂) Calibration Gas, ppmv	46.86	46.86	46.86	46.86
Analyzer NO₂ to NO Converter Efficiency	93.51	93.51	93.51	93.51
Initial System Calibration Bias for Zero Gas, % of Span	0.11	0.37	0.36	0.28
Initial System Calibration Bias for Upscale Gas, % of Span	-0.75	-1.15	-0.69	-0.86
Final System Calibration Bias for Zero Gas, % of Span	0.37	0.36	0.31	0.35
Final System Calibration Bias for Upscale Gas, % of Span	-1.15	-0.69	-0.57	-0.80
System Drift for Zero Gas, % of Span	0.27	-0.01	-0.05	0.07
System Drift for Upscale Gas, % of Span	-0.40	0.46	0.12	0.06
Analyzer Calibration Error for Zero Gas, % of Span	0.08	0.08	0.08	0.08
Analyzer Calibration Error for Mid-Level Gas, % of Span	-1.15	-1.15	-1.15	-1.15
Analyzer Calibration Error for High-Level Gas, % of Span	-0.39	-0.39	-0.39	-0.39

DETAILED RESULTS - DRY SYSTEM

Emission Results

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Average NO _x Mass Emission Rate (as NO ₂), (lb/MMBtu)	0.148	0.148	0.149	0.15

CONCENTRATION CALCULATIONS - DRY SYSTEM

Average Nitrogen Oxides (NO_x) Concentration

	<u>Run 1</u>	<u>Run 2</u>	<u>Run 3</u>	<u>Average</u>
Average NO _x Concentration Indicated by Gas Analyzer, ppmvd	115.35	115.89	117.57	116.27
Average of Initial and Final System Calibration Bias Check Responses for the Zero Gas, ppmvd	0.64	0.89	0.83	0.79
Average of Initial and Final System Calibration Bias Check Responses for the Upscale Calibration Gas, ppmvd	95.81	95.86	96.44	96.04
Average NO _x Concentration, ppmvd	120.54	121.09	122.10	121.24

EPA Method 1 (Round/Rectangular) - Stack/Duct Dimensions

Company: Howmet

Project ID: PROJ- 067458

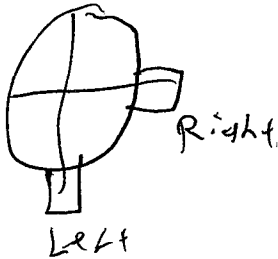
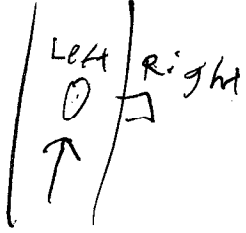
Location: Boo9

Technician: CE

Date: 4-23-26

	Port 1	Port 2	Port 3	Port 4	Port 5
Relative Location ¹	Left	Right			
From Far Inside Wall to Outside of Port (in.) ²	48.8	48.8			
Nipple Length and/or Wall Thickness (in.) ³	8.2	8.2			
Nipple Protrusion (in.) ⁴	1.0	1.0			
Stack/Duct Depth (Inner Dimension) (in.) ⁵ <u>41.6*</u>	~~40.8~~	~~40.8~~	<u>41.6*</u>		
Port Hole Inner Diameter (in.) ⁶	4	4			
Measured Particulate Build-up (in.) ⁷	-	-			
Stack/Duct Width (inner), if Rectangular (in.)				Port 6	Port 7
Number of Ports Traversed	2			1	
Direction of Flow and Stack Orientation:	Up/vertical			2	
Sample Port Access	Roof			3	
Elevation of Meter Box from Ground Level (ft)	-			4	
Elevation of Ports from Ground Level (ft)	30			5	
Isokinetic Sample (Yes / No)	No			6	
Elevation of Barometer from Ground Level (ft)	-			7	
Stack Outer Dimensions (in.)	128				
Distance Upstream from Flow Disturbance (in.)	96				
Disturbance Type: <u>Atmosphere</u>					
Distance Downstream from Flow Disturbance (in.)	150				
Disturbance Type: <u>Bend</u>					

* QC 4/28/26

Stack/Duct Cross Section Schematic 	Stack/Duct Flow Direction Schematic 
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QA/QC Check: Completeness [☒] Accuracy [☒] Specifications [☒]

Checked by: CE

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CEMS Traverse Point Determination - B009

Relative Port Location	1	2
From Far Wall to Outside of Port (in.)	48.8	48.8
Nipple Length or Wall Thickness (in.)	8.2	8.2
Port Protrusion Length (opt) (in.)	1.0	1.0
Depth of Stack or Duct (in.)	41.6	41.6
Stack or Duct Type	Circular	
Port Hole Inner Diameter (in.)	3.3	
Stack or Duct Width (If Rectangular) (in.)		
Stack Outer Circumference (in.)		
Number of Ports Traversed	2	
Elevation of Meter Box from Ground Level (ft)		
Elevation of Ports from Ground Level (ft)		
Stack Build-up (in.)	0.0	
Stack Cross-Sectional Diameter 1 (in)	41.6	
Stack Cross-Sectional Diameter 2 (in)	41.6	

"Vertical" or "Horizontal" Flow	Vertical
Direction of Flow	Up
"Velocity" or "Isokinetic" Traverse	Velocity

Port Distance Upstream from Flow Disturbance (in.)	96.0
Diameters Upstream from Flow Disturbance (* 0.5 De)	2.3
Minimum Traverse Points Needed for a Velocity Traverse *	12
Minimum Traverse Points Needed for a Isokinetic Traverse *	12

Port Distance Downstream from Flow Disturbance (in.)	150.0
Diameters Downstream from Flow Disturbance (* 2.0 De)	3.6
Minimum Traverse Points Needed for a Velocity Traverse *	16
Minimum Traverse Points Needed for a Isokinetic Traverse *	24

Minimum Traverse Points per Method 1	16
Number of Traverse Points for this Circular Stack or Duct	6
Point Override	6

Duct Area - in² 1359.18
Duct Area - ft² 9.4387

Note:

Add nipple protrusion length to Point 1 only.

Actual nipple length = (length - protrusion)

Relocate to a distance equal to the inside diameter of the nozzle being used or to the above minimum distances, whichever is larger.

This Stack having a diameter greater than 24-inches, shall have no traverse points located within 1.0-inch of the stack wall.

verified on 4/23/2026 by: CE

Port	Point	% of Duct Depth	Dist. From Inside Wall (Decimal)	Dist. From Outside Wall (Decimal)
1	1	16.7	6.9	14.1
1	2	50.0	20.8	28.0
1	3	83.3	34.7	41.9
2	1	16.7	6.9	14.1
2	2	50.0	20.8	28.0
2	3	83.3	34.7	41.9

Appendix A4 B008 Instrumental Test Method Data

Page: 1 of 1

CEMS Probe ID: T-CPR-*P4P-009*

Heated Sample Line ID(s): T-HSL- 105

Sample Conditioner ID(s): T-SCU- 121 D

Date	Run	Start	Stop	Pause Times/Process Notes/Comments/Concentrations #
4-23-26		11:09	11:29	EPA Method 205 Audit (CE 517441 + 50.1 ppm)
		11:34	11:40	EPA Method 7E Converter Efficiency NO _x
		11:43	12:03	Stratification Test Initial Calibrations
		12:06	12:18	Response Times
		12:56	13:07	Respan NO _x - 46.86 *
	+ 1	13:15	14:15	Meter #1: 886546 ccf Meter #1: Start Meter #2: 284925 ccf Meter #2:
		15:25		Pause 13:28 Boiler tripped
	+ 1	15:25	16:25	Pause 15:36 Boiler tripped
8008	1	16:45	17:45	838 ccf Natural Gas
		17:47	17:56	Drift check
	2	18:00	19:00	836 ccf Natural Gas
		19:01	19:10	Drift check
	3	19:15	20:15	847 ccf Natural Gas
		20:16	20:25	Drift check
4-24-25		11:33	11:56	Initial Calibrations
8009	1	12:30	13:30	could not move points due to hot steam
		13:31	13:40	Drift check 827 ccf natural gas
	2	13:45	14:45	838 ccf natural gas
		14:46	14:55	Drift check
	3	15:00	16:00	838 ccf natural gas
		16:01	16:11	Drift check
				* Date 4/30/26 per CE

Checked by: Q12

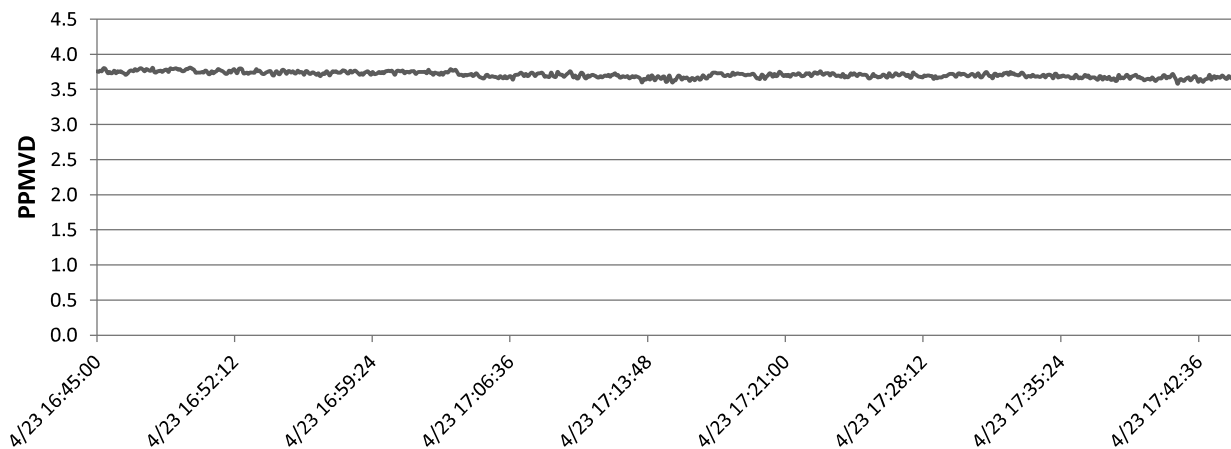
001AS-QMS-TM-68 Effective 4/22/2026

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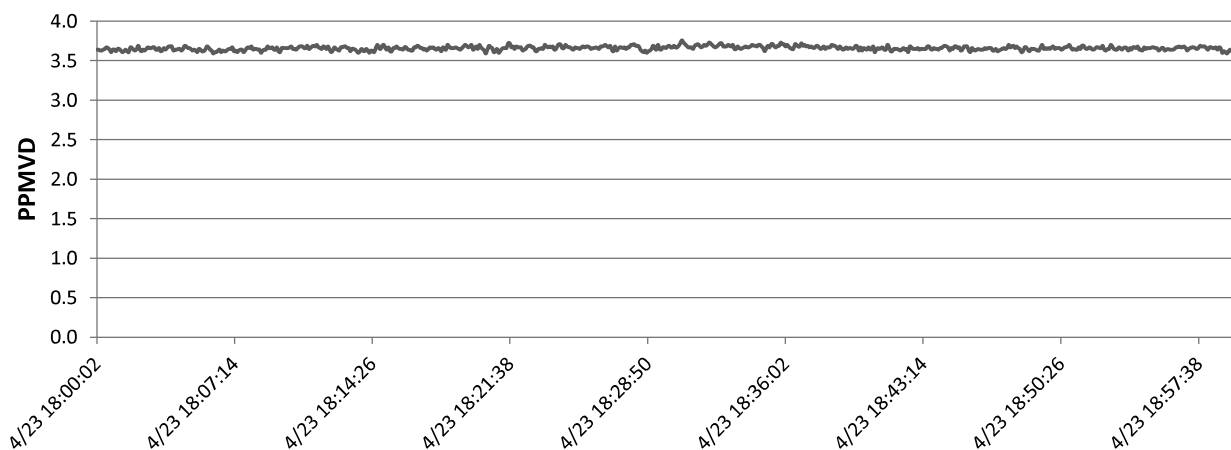
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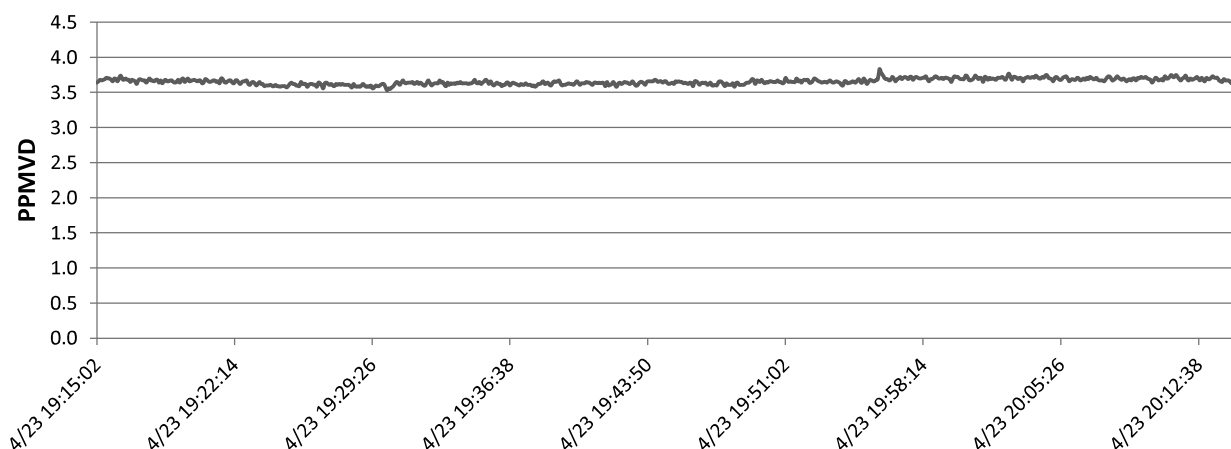
B008 Exhaust Stack - O2 Concentration - Run 1

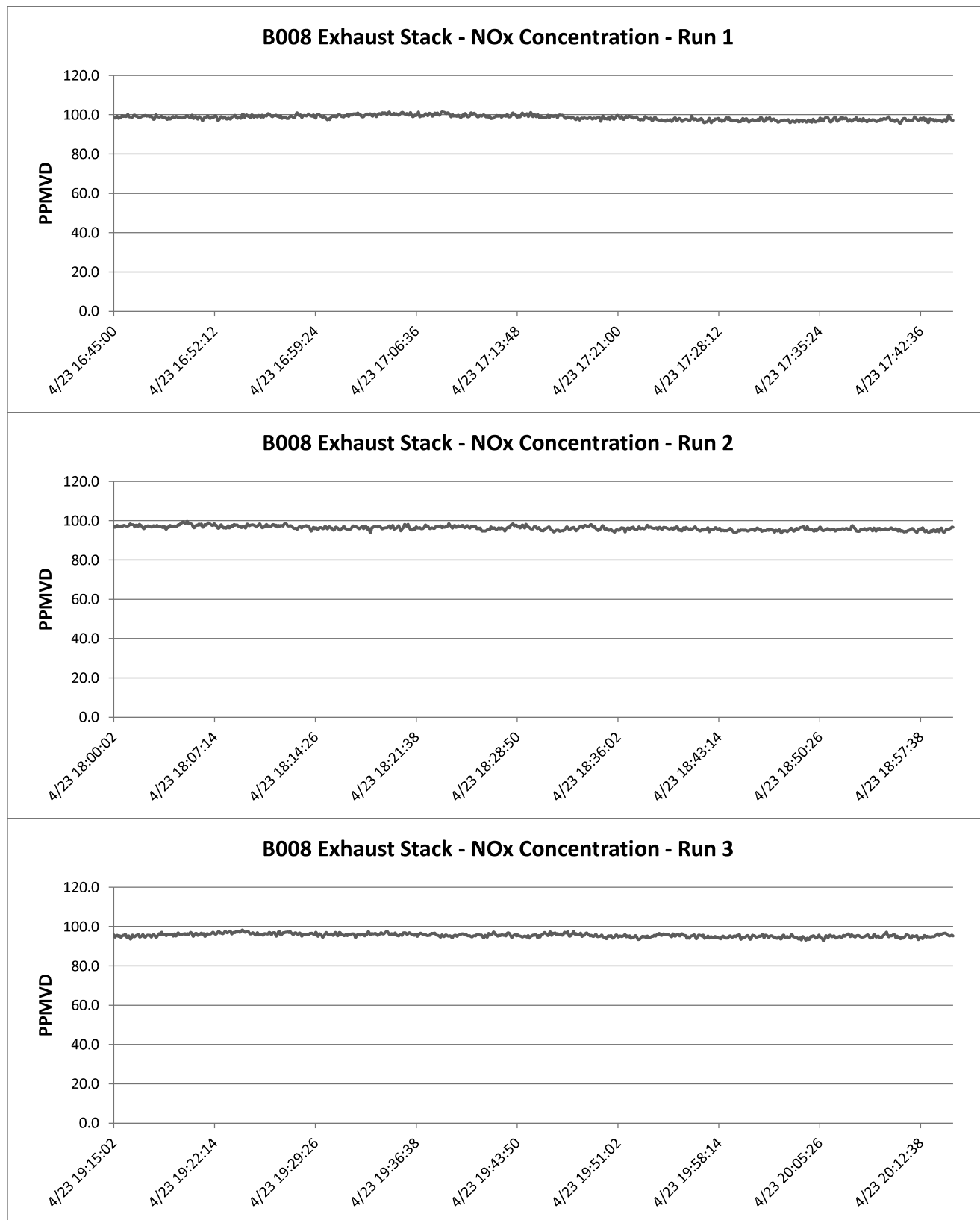


B008 Exhaust Stack - O2 Concentration - Run 2



B008 Exhaust Stack - O2 Concentration - Run 3





EPA M3A-O₂ Bias/Drift Sheet

Page 1 of 1

Company Howmet

System Response Time (RT), secs

Job ID: 067458

Run 1 - 60 s

Location: B008

Run 2 - 60 s

Analyzer Mfg and ID: Servomex/T-02602A-002

Run 3 - 60 s

Analyzer Model/Serial No.: 0144001-4926

Average 60 s

Technician: CE

	Actual/Target Value (%)	Pressure (psig)	Expiration (mm/dd/yy)	Cylinder ID
Zero-Level Gas Cylinder	<u>0</u>	<u>1500</u>	<u>1/13/2031</u>	<u>SKK7703</u>
Mid-Level Gas Cylinder	<u>22.05/11</u>	<u>1500</u>	<u>1/18/2031</u>	<u>CC72089</u>
High-Level Gas Cylinder	<u>22.05</u>	<u>1500</u>	<u>1/18/2031</u>	<u>CC72089</u>
EPA Method 205 Cylinder				<u>Method 205 Sheet</u>

Run Number	<u>1</u>	<u>2</u>	<u>3</u>		
Run Date	<u>4-23-26</u>	<u>4-23-26</u>	<u>4-23-26</u>		
Analyzer Span (%)	<u>22.05</u>	<u>22.05</u>	<u>22.05</u>		

Analyzer Calibration Response for Zero Gas	Time (hh:mm)	<u>1144</u>	<u>1144</u>	<u>1144</u>		
	Response (%)	<u>0.03</u>	<u>0.03</u>	<u>0.03</u>		
Analyzer Calibration Response for High Level Gas	Time (hh:mm)	<u>1146</u>	<u>1146</u>	<u>1146</u>		
	Response (%)	<u>22.02</u>	<u>22.02</u>	<u>22.02</u>		
Analyzer Calibration Response for Mid-Level Gas	Time (hh:mm)	<u>1148</u>	<u>1148</u>	<u>1148</u>		
	Response (%)	<u>11.04</u>	<u>11.04</u>	<u>11.04</u>		

Initial System Calibration Response for Zero Gas	Time (hh:mm)	<u>1158</u>	<u>1748</u>	<u>1903</u>		
	Response (%)	<u>0.07</u>	<u>0.09</u>	<u>0.07</u>		
Initial System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1200</u>	<u>1752</u>	<u>1906</u>		
	Response (%)	<u>10.92</u>	<u>10.91</u>	<u>10.85</u>		
Ambient Temp. (°F)						
Final System Calibration Response for Zero Gas	Time (hh:mm)	<u>1748</u>	<u>1903</u>	<u>2018</u>		
	Response (%)	<u>0.09</u>	<u>0.07</u>	<u>0.08</u>		
Final System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1752</u>	<u>1906</u>	<u>2021</u>		
	Response (%)	<u>10.91</u>	<u>10.85</u>	<u>10.87</u>		
Ambient Temp. (°F)						

QA/QC Check: Completeness [☒] Accuracy [☒] Specifications [☒]

Checked by: CE

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011AS-CEMS Methods Effective-04.22.26-EPA Method 3A-O2

EPA M7E-NO_x Bias/Drift Sheet

Page of

Company Howmet

System Response Time (RT), secs

Job ID: 067458

Run 1 - 90s

Location: BOOR

Run 2 - 60s

Analyzer Mfg and ID: CAI-700/T-NOA-025

Run 3 - 60s

Analyzer Model/Serial No.: 2110003

Average 70s

Technician: CE

	Actual/Target Value (%)	Pressure (psig)	Expiration (mm/dd/yy)	Cylinder ID
Zero-Level Gas Cylinder	<u>0</u>	<u>1500</u>	<u>1/13/2021</u>	<u>SKK 7703</u>
Mid-Level Gas Cylinder	<u>271/100</u>	<u>1000</u>	<u>3/30/2021</u>	<u>5X-63413</u>
High-Level Gas Cylinder	<u>271/200</u>	<u>1000</u>	<u>3/30/2021</u>	<u>5X-63413</u>
EPA Method 205 Cylinder				<u>See Method 205 sheet</u>

Run Number	<u>1</u>	<u>1</u>	<u>2</u>	<u>3</u>	
Run Date	<u>4-23-26</u>	<u>4-23-26</u>	<u>4-23-26</u>	<u>4-23-26</u>	
Analyzer Span (ppmv)	<u>100</u>	<u>200</u>	<u>200</u>	<u>200</u>	

Analyzer Calibration Response for Zero Gas	Time (hh:mm)	<u>1144</u>	<u>1258</u>	<u>1258</u>	<u>1258</u>	
	Response (%)	<u>0.18</u>	<u>0.18</u>	<u>0.18</u>	<u>0.18</u>	
Analyzer Calibration Response for High Level Gas	Time (hh:mm)	<u>1153</u>	<u>1301</u>	<u>1301</u>	<u>1301</u>	
	Response (%)	<u>99.89</u>	<u>199.21</u>	<u>199.21</u>	<u>199.21</u>	
Analyzer Calibration Response for Mid-Level Gas	Time (hh:mm)	<u>1155</u>	<u>1303</u>	<u>1303</u>	<u>1303</u>	
	Response (%)	<u>50.38</u>	<u>98.16</u>	<u>98.16</u>	<u>98.16</u>	

Initial System Calibration Response for Zero Gas	Time (hh:mm)	<u>0.325</u>	<u>1305</u>	<u>1748</u>	<u>1903</u>	
	Response (%)	<u>1158</u>	<u>0.68</u>	<u>0.88</u>	<u>0.71</u>	
Initial System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1203</u>	<u>1307</u>	<u>1756</u>	<u>1910</u>	
	Response (%)	<u>47.75</u>	<u>95.33</u>	<u>97.37</u>	<u>97.97</u>	
Ambient Temp. (°F)						
Final System Calibration Response for Zero Gas	Time (hh:mm)		<u>1748</u>	<u>1903</u>	<u>2018</u>	
	Response (%)		<u>0.88</u>	<u>0.71</u>	<u>0.82</u>	
Final System Calibration Response for Upscale Gas	Time (hh:mm)		<u>1756</u>	<u>1910</u>	<u>2025</u>	
	Response (%)		<u>97.37</u>	<u>97.97</u>	<u>98.02</u>	
Ambient Temp. (°F)						

QA/QC Check: Completeness [☒] Accuracy [☒] Specifications [☒]

Checked by: CE

001AS-QMS-TM-72

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011AS-CEMS Methods Effective-04.22.26-EPA Method 7E-NO_x

Appendix A5 B009 Instrumental Test Method Data

Page: 1 of 1

CEMS Probe ID: T-CPR-P4P-009

Heated Sample Line ID(s): T-HSL- 105

Sample Conditioner ID(s): T-SCU- 010

Date	Run	Start	Stop	Pause Times/Process Notes/Comments/Concentrations #
4-23-26		11:09	11:29	EPA Method 205 Audit (CE 517441 + 50.1 ppm)
		11:34	11:40	EPA Method 7E Converter Efficiency NO _x
		11:43	12:03	Stratification Test Initial Calibrations
		12:06	12:18	Response Times
		12:56	13:07	Respan NO _x - 46.86 *
	+ 1	13:15	14:15	Meter #1: 886546 ccf Meter #1: Start Meter #2: 284925 ccf Meter #2:
		15:25		Pause 13:28 Boiler tripped
	+ 1	15:25	16:25	Pause 15:36 Boiler tripped
8008	1	16:45	17:45	838 ccf Natural Gas
		17:47	17:56	Drift check
	2	18:00	19:00	836 ccf Natural Gas
		19:01	19:10	Drift check
	3	19:15	20:15	847 ccf Natural Gas
		20:16	20:25	Drift check
4-24-25		11:33	11:56	Initial Calibrations
8009	1	12:30	13:30	could not move points due to hot steam
		13:31	13:40	Drift check 827 ccf natural gas
	2	13:45	14:45	838 ccf natural gas
		14:46	14:55	Drift check
	3	15:00	16:00	838 ccf natural gas
		16:01	16:11	Drift check
				* QAC 4/30/26 per CE

Checked by: *Qiz*

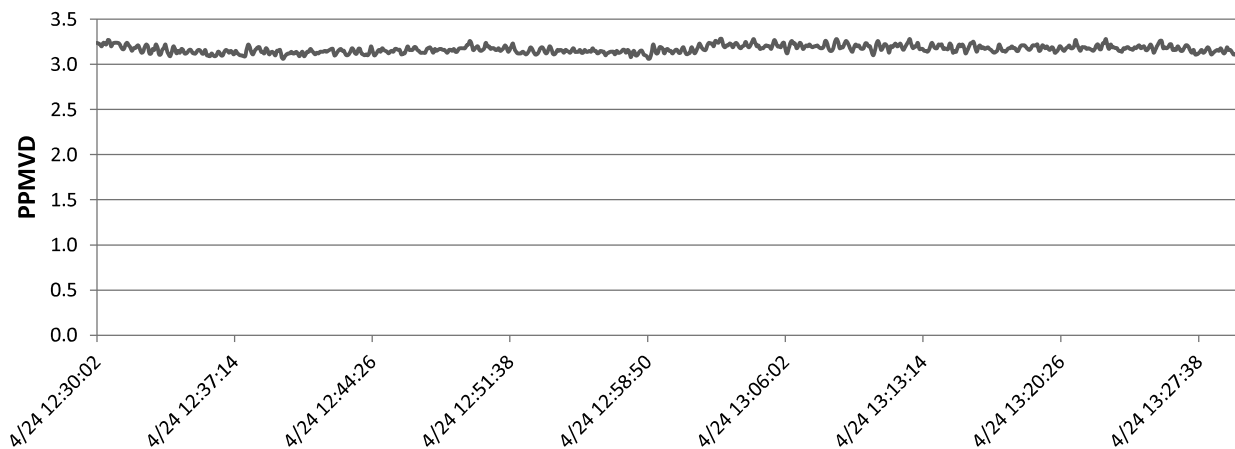
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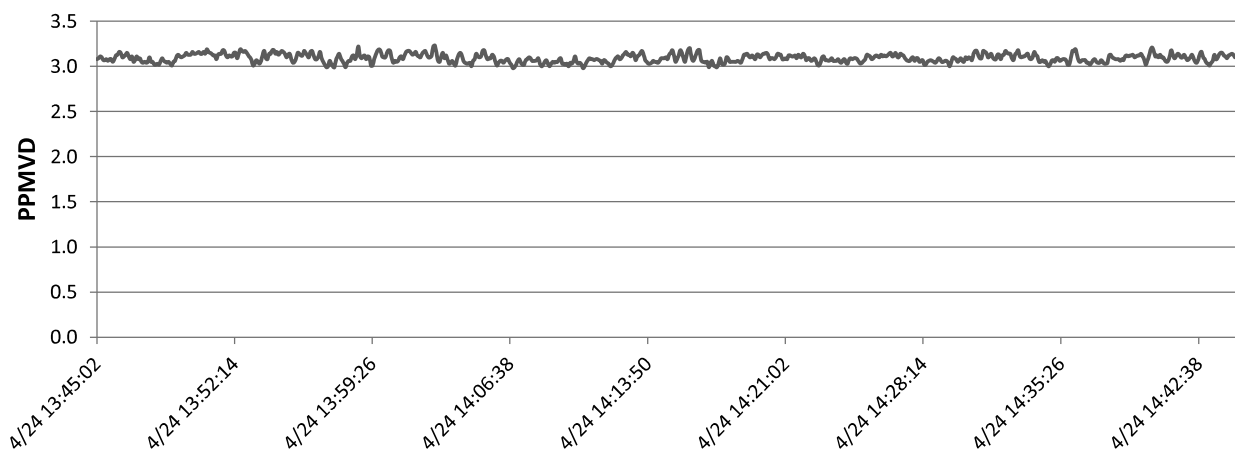
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011AS-CEMS Methods Effective-04.22.26-CEMS Log

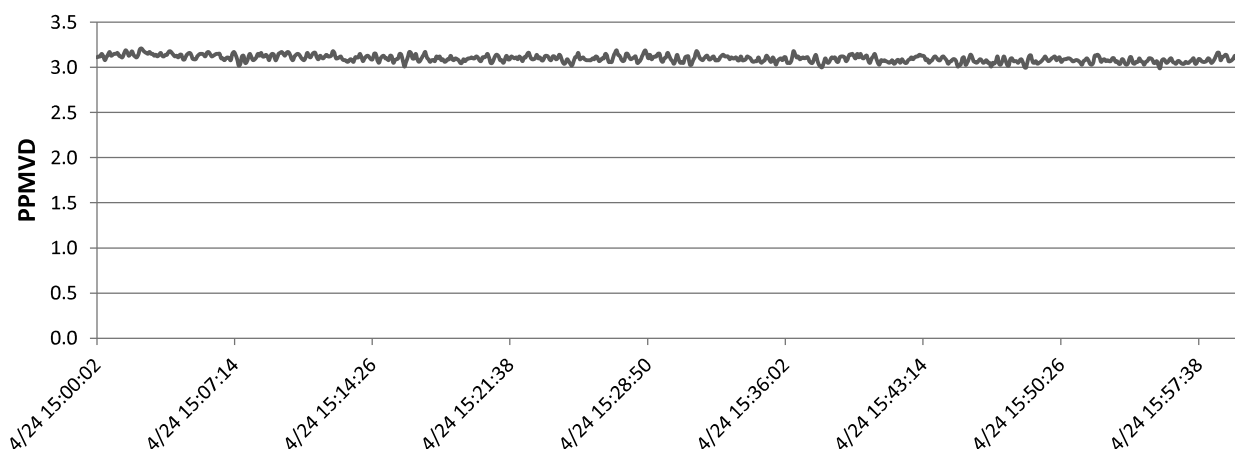
B009 Exhaust Stack - O2 Concentration - Run 1



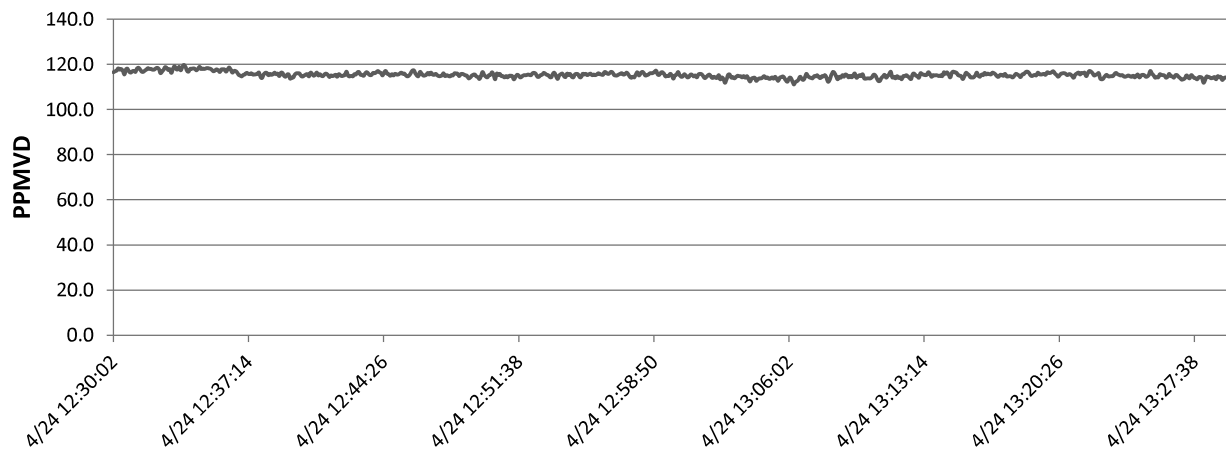
B009 Exhaust Stack - O2 Concentration - Run 2



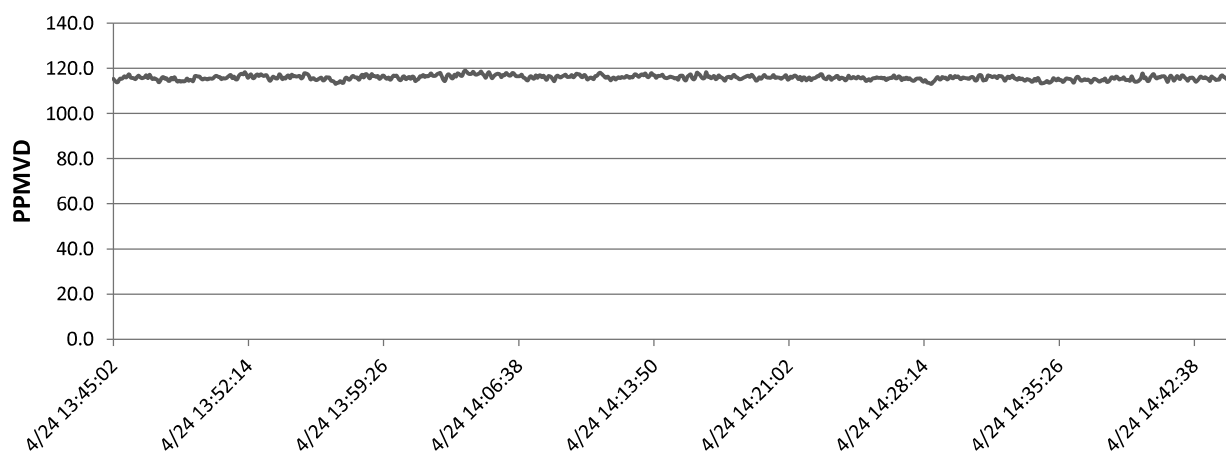
B009 Exhaust Stack - O2 Concentration - Run 3



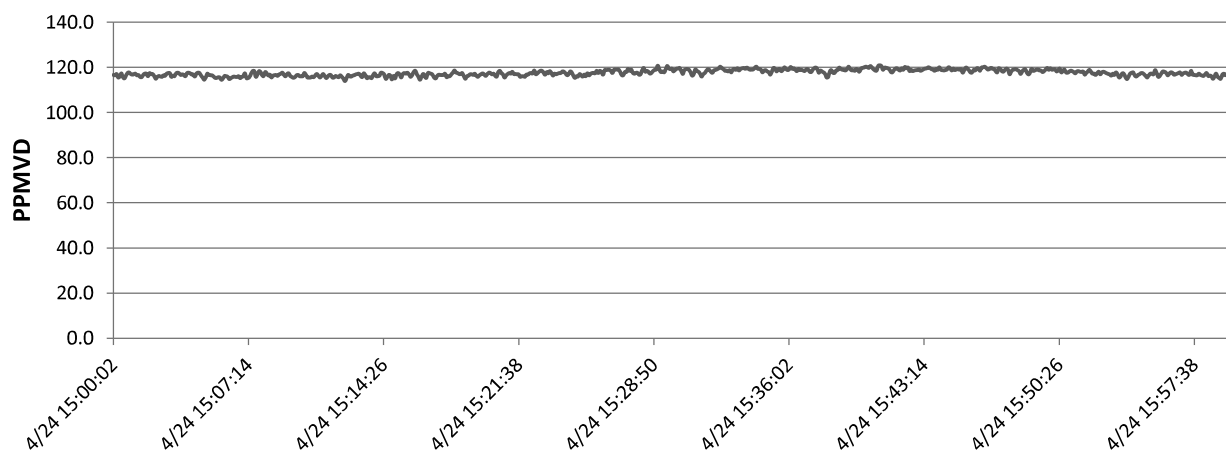
B009 Exhaust Stack - NOx Concentration - Run 1



B009 Exhaust Stack - NOx Concentration - Run 2



B009 Exhaust Stack - NOx Concentration - Run 3



EPA M3A-O₂ Bias/Drift Sheet

Page 1 of 1

Company <u>Howmet</u>	System Response Time (RT), secs	
Job ID: <u>067458</u>	Run 1 -	<u>60</u>
Location: <u>BDD9</u>	Run 2 -	<u>60</u>
Analyzer Mfg and ID: <u>Servomex / T-02 CO2 A-002</u>	Run 3 -	<u>60</u>
Analyzer Model/Serial No.: <u>0141001-4926</u>	Average	<u>60</u>
Technician: <u>CE</u>		

	Actual/Target Value (%)	Pressure (psig)	Expiration (mm/dd/yy)	Cylinder ID
Zero-Level Gas Cylinder	<u>0</u>	<u>1500</u>	<u>1/13/2031</u>	<u>SKK 7703</u>
Mid-Level Gas Cylinder	<u>22.05/11</u>	<u>1500</u>	<u>1/18/2031</u>	<u>CC72089</u>
High-Level Gas Cylinder	<u>22.05</u>	<u>1500</u>	<u>1/18/2031</u>	<u>CC72089</u>
EPA Method 205 Cylinder				<u>See Method 205 Sheet</u>

Run Number	<u>1</u>	<u>2</u>	<u>3</u>		
Run Date	<u>4-24-26</u>	<u>4-24-26</u>	<u>4-24-26</u>		
Analyzer Span (%)	<u>22.05</u>	<u>22.05</u>	<u>22.05</u>		

Analyzer Calibration Response for Zero Gas	Time (hh:mm)	<u>1135</u>	<u>1135</u>	<u>1135</u>		
	Response (%)	<u>0.09</u>	<u>0.09</u>	<u>0.09</u>		
Analyzer Calibration Response for High Level Gas	Time (hh:mm)	<u>1139</u>	<u>1139</u>	<u>1139</u>		
	Response (%)	<u>22.02</u>	<u>22.02</u>	<u>22.02</u>		
Analyzer Calibration Response for Mid-Level Gas	Time (hh:mm)	<u>1141</u>	<u>1141</u>	<u>1141</u>		
	Response (%)	<u>11.09</u>	<u>11.09</u>	<u>11.09</u>		

Initial System Calibration Response for Zero Gas	Time (hh:mm)	<u>1148</u>	<u>1333</u>	<u>1448</u>		
	Response (%)	<u>0.14</u>	<u>0.08</u>	<u>0.08</u>		
Initial System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1151</u>	<u>1335</u>	<u>1450</u>		
	Response (%)	<u>10.98</u>	<u>10.87</u>	<u>10.86</u>		
Ambient Temp. (°F)						
Final System Calibration Response for Zero Gas	Time (hh:mm)	<u>1333</u>	<u>1448</u>	<u>1604</u>		
	Response (%)	<u>0.08</u>	<u>0.08</u>	<u>0.07</u>		
Final System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1335</u>	<u>1450</u>	<u>1606</u>		
	Response (%)	<u>10.87</u>	<u>10.86</u>	<u>10.88</u>		
Ambient Temp. (°F)						

QA/QC Check: Completeness [☒] Accuracy [☐] Specifications [☒]

Checked by: CE

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011AS-CEMS Methods Effective-04.22.26-EPA Method 3A-O2

EPA M7E-NO_x Bias/Drift Sheet

Page 1 of 1

Company Howmet

System Response Time (RT), secs

Job ID: 067458

Run 1 - 90

Location: 8009

Run 2 - 60

Analyzer Mfg and ID: CAI-700/T-NOA-025

Run 3 - 60

Analyzer Model/Serial No.: 2110003

Average 70

Technician: CE

	Actual/Target Value (%)	Pressure (psig)	Expiration (mm/dd/yy)	Cylinder ID
Zero-Level Gas Cylinder	<u>0</u>	<u>1500</u>	<u>1/13/2021</u>	<u>8KK7703</u>
Mid-Level Gas Cylinder	<u>271/100</u>	<u>1000</u>	<u>3/30/2031</u>	<u>6X-63413</u>
High-Level Gas Cylinder	<u>271/200</u>	<u>1000</u>	<u>3/30/2031</u>	<u>6X-63413</u>
EPA Method 205 Cylinder				<u>see method 205 sheet</u>

Run Number	<u>1</u>	<u>2</u>	<u>3</u>		
Run Date	<u>4-24-26</u>	<u>4-24-26</u>	<u>4-24-26</u>		
Analyzer Span (ppmv)	<u>200</u>	<u>200</u>	<u>200</u>		

Analyzer Calibration Response for Zero Gas	Time (hh:mm)	<u>1135</u>	<u>1135</u>	<u>1135</u>		
	Response (%)	<u>0.16</u>	<u>0.16</u>	<u>0.16</u>		
Analyzer Calibration Response for High Level Gas	Time (hh:mm)	<u>1144</u>	<u>1144</u>	<u>1144</u>		
	Response (%)	<u>199.23</u>	<u>199.23</u>	<u>199.23</u>		
Analyzer Calibration Response for Mid-Level Gas	Time (hh:mm)	<u>1146</u>	<u>1146</u>	<u>1146</u>		
	Response (%)	<u>97.70</u>	<u>97.70</u>	<u>97.70</u>		

Initial System Calibration Response for Zero Gas	Time (hh:mm)	<u>1148</u>	<u>1333</u>	<u>1448</u>		
	Response (%)	<u>0.37</u>	<u>0.90</u>	<u>0.88</u>		
Initial System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1156</u>	<u>1340</u>	<u>1455</u>		
	Response (%)	<u>96.21</u>	<u>95.40</u>	<u>96.32</u>		
Ambient Temp. (°F)						
Final System Calibration Response for Zero Gas	Time (hh:mm)	<u>1333</u>	<u>1448</u>	<u>1604</u>		
	Response (%)	<u>0.90</u>	<u>0.88</u>	<u>0.78</u>		
Final System Calibration Response for Upscale Gas	Time (hh:mm)	<u>1340</u>	<u>1455</u>	<u>1611</u>		
	Response (%)	<u>95.40</u>	<u>96.32</u>	<u>96.56</u>		
Ambient Temp. (°F)						

QA/QC Check: Completeness [☒] Accuracy [☒] Specifications [☒]

Checked by: CE

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011AS-CEMS Methods Effective-04.22.26-EPA Method 7E-NO_x

Appendix A6 Example Calculations



EPA Methods 3A and 7E
Nomenclature and Sample Calculations

Customer Howmet
Computed By SAMK
Run Number 1 B009

Project Number PROJ-067458
Calculation Date 4/29/2026

Constants

CO ₂ F _{wt} =	44	in wg= 0.073529	NO ₂ F _{wt} = 46.01	HClF _{wt} = 36.46
O ₂ F _{wt} =	32	gr= 0.0001429	COF _{wt} = 28.01	SO ₂ F _{wt} = 64.06
CON ₂ F _{wt} =	28	mmBtu= 1000000 Btu	H ₂ SO ₄ F _{wt} = 98.08	Cl ₂ F _{wt} = 70.91
H ₂ O F _{wt} =	18.015	CF _{wt} = 12.011	T _{std} = 527.67	P _{std} = 29.92
ArF _{wt} =	39.95	PF _{wt} = 44.0962		

Stack Variables

percent O₂ by volume (dry basis) (dimensionless), %

F-factor, dry standard cubic feet per million BTU, ft³/mmBtu

<u>3.17</u>
<u>8710</u> Fd

Method 7E Calculations**NO_x concentration (ppmvd)**

$$\text{NO}_x \text{ ppmvd} = 120.54 \text{ ppmvd}$$

NO_x mass emission rate (lb/MMBtu)

$$\text{MERO}_{\text{NO}_x \text{ lb/MMBtu}} = (((\text{NO}_x \text{ ppmvd} \times 46.005 \times 8710) / (385.3 \times 10^6)) \times (20.9 / (20.9 - 3.17)))$$

$$\text{MERO}_{\text{NO}_x \text{ lb/MMBtu}} = 0.148 \text{ lb/MMBtu}$$

Note: The results calculated on this page may differ slightly from the results presented in the final report. This difference can be attributed to "significant digit round-off errors" common when comparing computer spreadsheets results with those derived from using a calculator.

Appendix B Facility Process Data

Howmet Aerospace Inc.
PROJ-067458

B008
Natural Gas Usage, CFM
4/23/2026

Run 1	Run 2	Run 3	Average
838	836	847	840

B009
Natural Gas Usage, CFM
4/24/2026

Run 1	Run 2	Run 3	Average
827	838	838	834

Appendix C Quality Assurance / Quality Control

Appendix C1 Units and Abbreviations

Unit	Description
@ X% O ₂	corrected to X% oxygen (corrected for dilution air)
CC	absolute value of the confidence coefficient
d	absolute value of the mean differences
°C	degrees Celsius
°F	degrees Fahrenheit
°R	degrees Rankine
" H ₂ O	inches of water column
13.6	specific gravity of mercury
ΔH	pressure drop across orifice meter, inches H ₂ O
ΔP	velocity head of stack gas, inches H ₂ O
θ	total sampling time, minutes
μg	microgram
ρ _a	density of acetone, mg/ml
ρ _w	density of water, 0.9982 g/ml or 0.002201 lb/ml
% vd	percent by volume, dry basis
% vw	percent by volume, wet basis
acfm	actual cubic feet of gas per minute at stack conditions
A _n	cross-sectional area of nozzle, ft ²
A _s	cross-sectional area of stack, square feet (ft ²)
Btu	British thermal unit
Btu/ft ³	British thermal units per cubic foot
Btu/gal	British thermal units per gallon
B _{ws}	proportion by volume of water vapor in gas stream
C _a	particulate matter concentration in stack gas, gr/acf
C _{Avg}	average unadjusted gas concentration, ppmv
C _{Dir}	measured concentration of calibration gas, ppmv
cf or ft ³	cubic feet
cfm	cubic feet per minute
C _{Gas}	average gas concentration adjusted for bias, ppmv
C _M	average of initial and final system bias check responses from upscale calibration gas, ppmv
cm or m ³	cubic meters
C _{MA}	actual concentration of the upscale calibration gas, ppmv
C _O	average of initial and final system bias check responses from low-level calibration gas, ppmv
C _p	pitot tube coefficient
C _s	particulate matter concentration in stack gas, gr/dscf
CS	calibration span, % or ppmv
C _S	measured concentration of calibration gas, ppmv
C _V	manufactured certified concentration of calibration gas, ppmv
D	drift assessment, % of span
dcf	dry cubic feet
dcm	dry cubic meters
D _n	diameter of nozzle, inches
D _s	diameter of stack, inches
dscf	dry standard cubic feet
dscf/MMBtu	dry standard cubic foot per million British thermal units
dscfm	dry standard cubic feet per minute
dscm	dry standard cubic meters
F _d	F-factor, dscf/MMBtu of heat input
fpm	feet per minute
fps	feet per second
ft	feet
ft ²	square feet
g	gram
gal	gallons
gal/hr	gallons per hour
gr	grains (7000 grains per pound)
gr/dscf	grains per dry standard cubic feet
GW	gigawatt
GWh	gigawatt-hour
hr	hour

Unit	Description
I	percent of isokinetic sampling
in	inch
k	kilo or thousand (metric units, multiply by 10^3)
K	kelvin (temperature)
K ₃	conversion factor 0.0154 gr/mg
K ₄	conversion factor 0.002668 ((in. Hg)(ft ³))/((ml)(°R))
kg	kilogram
K _p	pitot tube constant (85.49 ft/sec)
kwsfch	thousand wet standard cubic feet per hour
l or L	liters
lb/hr	pounds per hour
lb/lb-mole	pounds per pound mole
lb/MMBtu	pounds per million Btu
lb/TBtu	pounds per trillion Btu
lpm	liters per minute
m	meter or milli
M	thousand (English units) or mega (million, metric units)
m ³	cubic meters
m _a	mass of residue of acetone after evaporation, mg
M _d	molecular weight of stack gas; dry basis, lb/lb-mole
meq	milliequivalent
mg	milligram
Mg	megagram (10^6 grams)
min	minute
ml or mL	milliliter
mm	millimeter
MM	million (English units)
MMBtu	million British thermal units
MMBtu/hr	million Btu per hour
m _n	total amount of particulate matter collected, mg
mol	mole
mol. wt. or MW	molecular weight
M _s	molecular weight of stack gas; wet basis, lb/lb-mole
MW	molecular weight or megawatt
MWh	megawatt-hour
n	number of data points
ng	nanogram
nm	nanometer
Nm ³	normal cubic meter
P _{bar}	barometric pressure, inches Hg
pg	picogram
P _g	stack static pressure, inches H ₂ O
P _m	barometric pressure of dry gas meter, inches Hg
ppb	parts per billion
ppbv	parts per billion, by volume
ppbvd	parts per billion by volume, dry basis
ppm	parts per million
ppmv	parts per million, by volume
ppmvd	parts per million by volume, dry basis
ppmvw	parts per million by volume, wet basis
P _s	absolute stack gas pressure, inches Hg
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
P _{std}	standard absolute pressure, 29.92 inches Hg
Q _a	volumetric flow rate, actual conditions, acfm
Q _s	volumetric flow rate, standard conditions, scfm
Q _{std}	volumetric flow rate, dry standard conditions, dscfm
R	ideal gas constant 21.85 ((in. Hg) (ft ³))/((°R) (lbmole))
SB _{final}	post-run system bias check, % of span
SB _i	pre-run system bias check, % of span

Unit	Description
scf	standard cubic feet
scf/MMBtu	standard cubic foot per million British thermal units
scfh	standard cubic feet per hour
scfm	standard cubic feet per minute
scm	standard cubic meters
scmh	standard cubic meters per hour
sec	second
sf, sq. ft., or ft ²	square feet
std	standard
t	metric ton (1000 kg)
T _{0.975}	t-value
T _a	absolute average ambient temperature, °R (+459.67 for English)
T _m	absolute average dry gas meter temperature, °R (+459.67 for English)
ton or t	ton = 2000 pounds
tph or tons/hr	tons per hour
tpy or tons/yr	tons per year
T _s	absolute average stack gas meter temperature, °R (+459.67 for English)
T _{std}	absolute temperature at standard conditions
V	volt
V _a	volume of acetone blank, ml
V _{aw}	volume of acetone used in wash, ml
V _{lc}	total volume H ₂ O collected in impingers and silica gel, grams
V _m	volume of gas sampled through dry gas meter, ft ³
V _{m(std)}	volume of gas measured by the dry gas meter, corrected to standard conditions, dscf
V _{ma}	stack gas volume sampled, acf
V _n	volume collected at stack conditions through nozzle, acf
V _s	average stack gas velocity, feet per second
V _{wc(std)}	volume of water vapor condensed, corrected to standard conditions, scf
V _{wi(std)}	volume of water vapor in gas sampled from impingers, scf
V _{wsg(std)}	volume of water vapor in gas sampled from silica gel, scf
W	watt
W _a	weight of residue in acetone wash, mg
W _{imp}	total weight of impingers, grams
W _{sg}	total weight of silica gel, grams
Y	dry gas meter calibration factor, dimensionless

Abbreviations

Acronym	Description
ACE	analyzer calibration error
AAS	atomic absorption spectroscopy
ACDP	air contaminant discharge permit
AD	absolute difference
ADL	above detection limit
AETB	Air Emissions Testing Body
APCD	air pollution control device
APCS	air pollution control system
AS	applicable standard (emission limit)
ASTM	American Society For Testing And Materials
BACT	best achievable control technology
BDL	below detection limit
BHP	brake horsepower
BIF	boiler and industrial furnace
BLS	black liquor solids
CARB	California Air Resources Board
CC	confidence coefficient
CD	calibration drift
CE	capture efficiency or collection efficiency
CEM	continuous emissions monitor
CEMS	continuous emissions monitoring system
CERMS	continuous emissions rate monitoring system
CET	calibration error test
CFB	circulating fluidized bed
CFR	Code of Federal Regulations
CGA	cylinder gas audit
CHNOS	elemental analysis for determination of C, H, N, O, and S content in fuels
CNCG	concentrated non-condensable gas
CO	catalytic oxidizer
COC	chain of custody
COMS	continuous opacity monitoring system
CPM	condensable particulate matter
CPMS	continuous parameter monitoring system
CT	combustion turbine
CTM	conditional test method
CTO	catalytic thermal oxidizer
CTS	calibration transfer standard
CVAAS	cold vapor atomic absorption spectroscopy
CVAFS	cold vapor atomic fluorescence spectrometry
De	equivalent diameter
DE	destruction efficiency
DGM	dry gas meter
Dioxins	polychlorinated dibenzo-p-dioxins (PCDDs)
DLL	detection level limited
DNCG	dilute non-condensable gas
EAF	electric arc furnace
ECD	electron capture detector
EGU	electric utility steam generating unit
EIT	Engineer In Training
ELCD	electrolytic conductivity detector (hall detector)
EMPC	estimated maximum possible concentration
EPA	US Environmental Protection Agency
EPRI	Electric Power Research Institute
ES	emission standard (applicable limit)
ESP	electrostatic precipitator
ERT	Electronic Reporting Tool
EU	emission unit
FB	field blank
FCCU	fluid catalytic cracking unit
FGD	flue gas desulfurization
FI	flame ionization

Abbreviations

Acronym	Description
FIA	flame ionization analyzer
FID	flame ionization detector
FPD	flame photometric detector
FPM	filterable particulate matter
FTIR	Fourier-transform infrared spectroscopy
FTPb	field train proof blank
FTRb	field train recovery blank
Furans	polychlorinated dibenzofurans (PCDFs)
GC	gas chromatography
GC/MS	gas chromatography/mass spectroscopy
GFAAS	graphite furnace atomic absorption spectroscopy
GFC	gas filter correlation
GHG	greenhouse gas
HAP	hazardous air pollutant
HC	hydrocarbons
HHV	higher heating value
HI	heat input
HPLC	high performance liquid chromatography
HRGC/HRMS	high-resolution gas chromatography/high-resolution mass spectroscopy
HRSG	heat recovery steam generator
IC	ion chromatography
ICAP	inductively-coupled argon plasma emission spectroscopy
ICPCR	ion chromatography with a post-column reactor
ICP-MS	inductively coupled plasma-mass spectroscopy
ICR	information collection request
IR	infrared radiation
ISDL	in-stack detection limit
ISE	ion-specific electrode
ISO	International Standards Organization
kW	kilowatts
LEE	low emitting EGU
LFG	landfill gas
LHV	lower heating value
LPG	liquified petroleum gas
LRGC/LRMS	low-resolution gas chromatography/low-resolution mass spectroscopy
MACT	maximum achievable control technology
MATS	Mercury and Air Toxics Standard
MDI	methylene diphenyl diisocyanate
MDL	method detection limit
MNOC	maximum normal operating conditions
MRL	method reporting limit
MS	mass spectrometry
MSW	municipal solid waste
MWC	municipal waste combustor
NA	not applicable or not available
NCASI	National Council For Air And Steam Improvement
NCG	non-condensable gases
ND	not detected
NDIR	non-dispersive infrared
NDO	natural draft opening
NESHAP	National Emissions Standards For Hazardous Air Pollutants
NG	natural gas
NIOSH	National Institute For Occupational Safety And Health
NIST	National Institute Of Standards And Technology
NMC	non-methane cutter
NMEOC	non-methane, non-ethane organic compounds
NMOC	non-methane organic compounds
NMVOC	non-methane volatile organic compounds
NPD	nitrogen phosphorus detector
NSPS	New Source Performance Standards
OSHA	Occupational Safety And Health Administration

Abbreviations

Acronym	Description
PAH	polycyclic aromatic hydrocarbons
PCB	polychlorinated biphenyl compounds
PCWP	plywood and composite wood products
PE	Professional Engineer
PEMS	predictive emission monitoring system
PFAS	per- and polyfluoroalkyl substances (PFAS)
PI	photoionization
PID	photoionization detector
PM	particulate matter
PM ₁₀	particulate matter less than 10 microns in aerodynamic diameter
PM _{2.5}	particulate matter less than 2.5 microns in aerodynamic diameter
PMS	parametric monitoring system
PPE	personal protective equipment
POM	polycyclic organic matter
PS	performance specification
PSD	particle size distribution
PSEL	plant site emission limits
PST	performance specification test
PTE	permanent total enclosure
PTM	performance test method
QA/QC	quality assurance and quality control
QI	Qualified Individual
QSTI	Qualified Source Test Individual
QSTO	Qualified Source Test Observer
RA	relative accuracy
RAA	relative accuracy audit
RACT	reasonably available control technology
RATA	relative accuracy test audit
RCA	response correlation audit
RB	reagent blank
RCTO	rotary concentrator thermal oxidizer
RE	removal or reduction efficiency
RICE	stationary reciprocating internal combustion engine
RM	reference method
RRA	relative response audit
RTO	regenerative thermal oxidizer
SAM	sulfuric acid mist
SCD	sulfur chemiluminescent detector
SCR	selective catalytic reduction system
SD	standard deviation
Semi-VOST	semi-volatile organic compounds sample train
SI ICE	spark ignition internal combustion engine
SLU	scattered light units
SNCR	selective noncatalytic reduction
SRM	standard reference material
SSI	sewage sludge incineration
STMS	sorbent trap monitoring system
TAP	toxic air pollutant
TBD	to be determined
TCA	thermal conductivity analyzer
TCD	thermal conductivity detector
TEF	toxic equivalency factor
TEQ	toxic equivalency quotient
TGNENMOC	total gaseous non-ethane non-methane organic compounds
TGNMOC	total gaseous non-methane organic compounds
TGOC	total gaseous organic compounds
THC	total hydrocarbons
TIC	tentatively identified compound
TO	thermal oxidizer
TO	toxic organic (as in EPA Method TO-15)
TPM	total particulate matter

Abbreviations



Acronym	Description
TSP	total suspended particulate matter
TTE	temporary total enclosure
ULSD	ultra-low sulfur diesel
US EPA	United States Environmental Protection Agency
UV	ultraviolet radiation range
VE	visible emissions
VOC	volatile organic compounds
VOST	volatile organic sample train
WC	water column
WWTP	waste water treatment plant

Acronym	Description
Ag	silver
As	arsenic
Ba	barium
Be	beryllium
Br ₂	bromine
C	carbon
Cd	cadmium
CdS	cadmium sulfide
CH ₂ O	formaldehyde
CH ₃ CHO	acetaldehyde
CH ₃ OH	methanol
CH ₄	methane
C ₂ H ₄ O	ethylene oxide
C ₂ H ₆	ethane
C ₃ H ₄ O	acrolein
C ₃ H ₆ O	propionaldehyde
C ₃ H ₈	propane
C ₆ H ₅ OH	phenol
C ₆ H ₁₄	hexane
Cl ₂	chlorine
ClO ₂	chlorine dioxide
CO	carbon monoxide
Co	cobalt
CO ₂	carbon dioxide
Cr	chromium
Cu	copper
EtO	ethylene oxide
EtOH	ethyl alcohol (ethanol)
H ₂	hydrogen
H ₂ O	water
H ₂ O ₂	hydrogen peroxide
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid
HBr	hydrogen bromide
HCl	hydrogen chloride
HF	hydrogen fluoride
Hg	mercury
IPA	isopropyl alcohol
MDI	methylene diphenyl diisocyanate
MeCl ₂	methylene chloride
MEK	methyl ethyl ketone
MeOH	methanol
Mn	manganese
N ₂	nitrogen
NH ₃	ammonia
Ni	nickel
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
O ₂	oxygen
P	phosphorus
Pb	lead
PCDD	polychlorinated dibenzo-p-dioxins
PCDF	polychlorinated dibenzofurans
Sb	antimony
Se	selenium
SO ₂	sulfur dioxide
SO ₃	sulfur trioxide
SO _x	sulfur oxides
TCDD	tetrachlorodibenzodioxin
TCDF	tetrachlorodibenzofuran

Acronym	Description
TGOC	total gaseous organic concentration
THC	total hydrocarbons
TI	thallium
TRS	total reduced sulfur compounds
Zn	zinc

Appendix C2 Instrumental Test Method QA/QC Data

US EPA REFERENCE METHOD 3A (O2) ANALYZER CALIBRATION AND QA

B008 Exhaust Stack							
OXYGEN ANALYZER		RUN 1	Acceptable	RUN 2	Acceptable	RUN 3	Acceptable
Analyzer Span During Test Run (%)	22.05	YES		22.05	YES	22.05	YES
Initial System Calibration Response for Zero Gas (%)	0.07	N/A		0.09	N/A	0.07	N/A
Final System Calibration Response for Zero Gas (%)	0.09	N/A		0.07	N/A	0.08	N/A
Actual Concentration of the Upscale Calibration Gas (%)	22.05	N/A		22.05	N/A	22.05	N/A
Initial System Calibration Response for Upscale Gas (%)	10.92	N/A		10.91	N/A	10.85	N/A
Final System Calibration Response for Upscale Gas (%)	10.91	N/A		10.85	N/A	10.87	N/A
Initial System Calibration Bias for Zero Gas (% of Span)	0.18	YES		0.27	YES	0.18	YES
Final System Calibration Bias for Zero Gas (% of Span)	0.27	YES		0.18	YES	0.23	YES
Initial System Calibration Bias for Upscale Gas (% of Span)	-0.54	YES		-0.59	YES	-0.86	YES
Final System Calibration Bias for Upscale Gas (% of Span)	-0.59	YES		-0.86	YES	-0.77	YES
System Drift for Zero Gas (% of Span)	0.09	YES		-0.09	YES	0.05	YES
System Drift for Upscale Gas (% of Span)	-0.05	YES		-0.27	YES	0.09	YES
Analyzer Calibration Error for Zero Gas (% of Span)	0.14	YES		0.14	YES	0.14	YES
Analyzer Calibration Error for Mid-Level Gas (% of Span)	0.18	YES		0.18	YES	0.18	YES
Analyzer Calibration Error for High-Level Gas (% of Span)	-0.14	YES		-0.14	YES	-0.14	YES

US EPA REFERENCE METHOD 7E ANALYZER CALIBRATION AND QA

B008 Exhaust Stack							
NITROGEN OXIDES ANALYZER		RUN 1 Acceptable		RUN 2 Acceptable		RUN 3 Acceptable	
Analyzer Span During Test Run (ppm)	200.00	YES	200.00	YES	200.00	YES	
Initial System Calibration Response for Zero Gas (ppm)	0.68	N/A	0.88	N/A	0.71	N/A	
Final System Calibration Response for Zero Gas (ppm)	0.88	N/A	0.71	N/A	0.82	N/A	
Actual Concentration of the Upscale Calibration Gas (ppm)	200.00	N/A	200.00	N/A	200.00	N/A	
Initial System Calibration Response for Upscale Gas (ppm)	95.33	N/A	97.37	N/A	97.97	N/A	
Final System Calibration Response for Upscale Gas (ppm)	97.37	N/A	97.97	N/A	98.02	N/A	
Initial System Calibration Bias for Zero Gas (% of Span)	0.25	YES	0.35	YES	0.27	YES	
Final System Calibration Bias for Zero Gas (% of Span)	0.35	YES	0.27	YES	0.32	YES	
Initial System Calibration Bias for Upscale Gas (% of Span)	-1.42	YES	-0.39	YES	-0.09	YES	
Final System Calibration Bias for Upscale Gas (% of Span)	-0.39	YES	-0.09	YES	-0.07	YES	
System Drift for Zero Gas (% of Span)	0.10	YES	-0.09	YES	0.06	YES	
System Drift for Upscale Gas (% of Span)	1.02	YES	0.30	YES	0.02	YES	
Analyzer Calibration Error for Zero Gas (% of Span)	0.09	YES	0.09	YES	0.09	YES	
Analyzer Calibration Error for Mid-Level Gas (% of Span)	-0.92	YES	-0.92	YES	-0.92	YES	
Analyzer Calibration Error for High-Level Gas (% of Span)	-0.39	YES	-0.39	YES	-0.39	YES	

US EPA REFERENCE METHOD 3A (O2) ANALYZER CALIBRATION AND QA

B009 Exhaust Stack							
OXYGEN ANALYZER		RUN 1	Acceptable	RUN 2	Acceptable	RUN 3	Acceptable
Analyzer Span During Test Run (%)		YES		22.05		YES	
Initial System Calibration Response for Zero Gas (%)	0.14	N/A		0.08		N/A	
Final System Calibration Response for Zero Gas (%)	0.08	N/A		0.08		N/A	
Actual Concentration of the Upscale Calibration Gas (%)	22.05	N/A		22.05		N/A	
Initial System Calibration Response for Upscale Gas (%)	10.98	N/A		10.87		N/A	
Final System Calibration Response for Upscale Gas (%)	10.87	N/A		10.86		N/A	
Initial System Calibration Bias for Zero Gas (% of Span)	0.23	YES		-0.05		YES	
Final System Calibration Bias for Zero Gas (% of Span)	-0.05	YES		-0.05		YES	
Initial System Calibration Bias for Upscale Gas (% of Span)	-0.50	YES		-1.00		YES	
Final System Calibration Bias for Upscale Gas (% of Span)	-1.00	YES		-1.04		YES	
System Drift for Zero Gas (% of Span)	-0.27	YES		0.00		YES	
System Drift for Upscale Gas (% of Span)	-0.50	YES		-0.05		YES	
Analyzer Calibration Error for Zero Gas (% of Span)	0.41	YES		0.41		YES	
Analyzer Calibration Error for Mid-Level Gas (% of Span)	0.41	YES		0.41		YES	
Analyzer Calibration Error for High-Level Gas (% of Span)	-0.14	YES		-0.14		YES	

US EPA REFERENCE METHOD 7E ANALYZER CALIBRATION AND QA

B009 Exhaust Stack							
NITROGEN OXIDES ANALYZER		RUN 1 Acceptable		RUN 2 Acceptable		RUN 3 Acceptable	
Analyzer Span During Test Run (ppm)	200.00	YES		200.00	YES	200.00	YES
Initial System Calibration Response for Zero Gas (ppm)	0.37	N/A		0.90	N/A	0.88	N/A
Final System Calibration Response for Zero Gas (ppm)	0.90	N/A		0.88	N/A	0.78	N/A
Actual Concentration of the Upscale Calibration Gas (ppm)	200.00	N/A		200.00	N/A	200.00	N/A
Initial System Calibration Response for Upscale Gas (ppm)	96.21	N/A		95.40	N/A	96.32	N/A
Final System Calibration Response for Upscale Gas (ppm)	95.40	N/A		96.32	N/A	96.56	N/A
Initial System Calibration Bias for Zero Gas (% of Span)	0.11	YES		0.37	YES	0.36	YES
Final System Calibration Bias for Zero Gas (% of Span)	0.37	YES		0.36	YES	0.31	YES
Initial System Calibration Bias for Upscale Gas (% of Span)	-0.75	YES		-1.15	YES	-0.69	YES
Final System Calibration Bias for Upscale Gas (% of Span)	-1.15	YES		-0.69	YES	-0.57	YES
System Drift for Zero Gas (% of Span)	0.27	YES		-0.01	YES	-0.05	YES
System Drift for Upscale Gas (% of Span)	-0.40	YES		0.46	YES	0.12	YES
Analyzer Calibration Error for Zero Gas (% of Span)	0.08	YES		0.08	YES	0.08	YES
Analyzer Calibration Error for Mid-Level Gas (% of Span)	-1.15	YES		-1.15	YES	-1.15	YES
Analyzer Calibration Error for High-Level Gas (% of Span)	-0.39	YES		-0.39	YES	-0.39	YES

US EPA METHOD 7E NO_x CONVERTER CHECK

Parameter		Allowable
Date	4/23/2026	--
Time	11:39	--
Certified Cylinder ID	CC517441	--
Certified Cylinder Concentration, ppm NO ₂	50.11	--
AnalyzerResponse, ppm NO _x	46.86	--
Conversion Efficiency, %	93.51	≥ 90

**MATHESON**

The Gas Professionals

Certificate of Batch Analysis

To:

Sales Order No:

Purchase Order:

Manufacturing Location

Matheson
1650 Enterprise Parkway
Twinsburg, OH 44087

Product: Nitrogen**Grade:** UHP**Part No:** NI UHP 300**Cylinder Size:** 1L**Valve:** CGA 580BR**Pressure:** 2640 psig**Contents:** 300 CF**CYLINDER NUMBER(S)**

TC-3AAM
SKK 7703

Component	Specification	Certified Concentration	Units (mol)	Analytical Method
Nitrogen	99.999	99.999	%	
Carbon Dioxide	<1	<1	ppm	I
Carbon Monoxide	<1	<1	ppm	I
Oxygen	<2	<2	ppm	A
THC	<0.5	<0.5	ppm	I
Water	<3	<3	ppm	F

COMMENTS

Product Composition verified by instrumentation calibrated with at least one of the following: NIST traceable weights, gas mixtures traceable to NIST weights, NIST gas standards such as NTRM's or SRM's, manufacturer NIST calibrations.

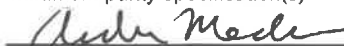
Analytical Method Key

A	Trace oxygen analyzer	G	Detector Tubes
B	Gas chromatograph with thermal conductivity detector	H	Gas chromatograph with helium ionization detector
C	Gas chromatograph with flame ionization detector	I	Gas chromatograph with discharge ionization detector
D	Trace nitrogen analyzer	J	Specific carbon monoxide analyzer
E	Total hydrocarbon analyzer	K	Percent oxygen analyzer
F	Specific moisture analyzer	L	Specific carbon dioxide analyzer
		M	Binary gas mixture analyzer

Lot No: 013N416202**Fill Date:** 1/13/2026**IMPORTANT**

The information contained herein has been prepared at your request by qualified experts within Matheson. While we believe that the information is accurate within the limits of the analytical methods employed and is complex to the extent of the specified analysis performed, we make no warranty or representation as to the suitability of the use of the information for any particular purpose. The information is offered with the understanding that any use of the information is at the sole discretion and risk of the user. In no event shall the liability of Matheson arising out of the use of the information contained herein exceed the fee established for providing such information.

The undersigned certifies that the product(s) listed above reflect gas phase by volume (unless otherwise indicated) and meet or exceed the minimum purity specification(s)


Analyst

01/22/26
Date

Form effective date - May 27, 2022

CERTIFICATE OF ANALYSIS

Grade of Product: EPA PROTOCOL STANDARD

Part Number:	E03NI56E15A1055	Reference Number:	54-402640739-1
Cylinder Number:	CC72089	Cylinder Volume:	162.0 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12023	Valve Outlet:	590
Gas Code:	CO2,O2,BALN	Certification Date:	Jan 18, 2023

Expiration Date: Jan 18, 2031

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted. The results relate only to the items tested. The report shall not be reproduced except in full without approval of the laboratory. Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS					
Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
CARBON DIOXIDE	22.00 %	21.81 %	G1	+/- 0.6% NIST Traceable	01/18/2023
OXYGEN	22.00 %	22.05 %	G1	+/- 0.6% NIST Traceable	01/18/2023
NITROGEN	Balance				

CALIBRATION STANDARDS					
Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	200605	6088271Y	24.63 % CARBON DIOXIDE/NITROGEN	+/- 0.4%	Feb 08, 2027
NTRM	08010217	K011889	23.20 % OXYGEN/NITROGEN	+/- 0.4%	Jun 01, 2024

ANALYTICAL EQUIPMENT		
Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
CO2-2 SIEMENS ULTRAMAT 6E N1N4470	NDIR	Jan 10, 2023
O2-1 HORIBA MPA-510 3VUYL9NR	Paramagnetic	Jan 18, 2023

Triad Data Available Upon Request



Approved for Release

**MATHESON**

The Gas Professionals

1650 Enterprise Parkway
Twinsburg, OH 44087
215-648-4000**Certificate of Analysis – EPA Protocol Mixtures**Customer: Montrose Air Quality Services
Cylinder Number: SX- 63413
Cylinder Pressure: 1800 psig
Certification Date: 3/30/2023
Certification Expiration Date: 3/30/2031Protocol: G1 Reference #: 830047 Lot #: 109-96-45449
Part #: G 2679601**DO NOT USE THIS CYLINDER WHEN THE
PRESSURE FALLS BELOW 100 PSIG**

Component: Nitric Oxide

Certified Conc: 271 ppm +/- 3 ppm

REPLICATE RESPONSES

Date:	3/22/2023	Date:	3/30/2023
	271 ppm		271 ppm
	271 ppm		271 ppm
	271 ppm		271 ppm

BALANCE GAS: Nitrogen

REFERENCE STANDARDS:Component: Nitric Oxide
Standard #: NTRM-101019
Sample # / Cert No.: 191102-09
Cylinder #: SZ18200
Concentration: 252.1±2.3 ppm
Expires: 6/9/26**CERTIFICATION INSTRUMENTS**Component: Nitric Oxide
Make/Model: Horiba CLA-510SS
Serial Number: 4LKB3FHH
Measurement Principle: Chemiluminescence
Last Calibration: 3/15/2023

Notes: NOx = 271 ppm REFERENCE VALUE ONLY

The certification was performed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards May 2012, using procedure G1 and/or G2. U.S EPA Vendor ID Number: D42023, PGVP Participation Date: 01/01/23, PGVP Renewal Date: 01/01/24. The expanded uncertainty listed for each component was calculated at a coverage factor of k=2 and at a level of confidence of 95%.

Analyst: WJ

Issued Date: 3/31/2023

Accredited By:
ANAB

NE011AS-067458-RT-2711

CERTIFICATE OF ANALYSIS

Grade of Product: EPA PROTOCOL STANDARD

Part Number:	E02AI99E15W0021	Reference Number:	122-403370485-1
Cylinder Number:	CC517441	Cylinder Volume:	146.0 CF
Laboratory:	124 - Durham (SAP) - NC	Cylinder Pressure:	2015 PSIG
PGVP Number:	B22025	Valve Outlet:	660
Gas Code:	NO2,BALA	Certification Date:	Jun 27, 2025

Expiration Date: Jun 27, 2028

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted. The results relate only to the items tested. The report shall not be reproduced except in full without approval of the laboratory. Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NITROGEN DIOXIDE AIR	50.00 PPM Balance	50.11 PPM	G1	+/- 2.0% NIST Traceable	06/20/2025, 06/27/2025

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
GMIS	1534002024	CC502861	60.09 PPM NITROGEN DIOXIDE/NITROGEN	+/- 1.8%	Apr 04, 2027
PRM	C2392001.03	D153564	59.5 PPM NITROGEN DIOXIDE/AIR	+/- 1.7%	Nov 22, 2024

The SRM, NTRM, PRM, or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
MKS FTIR NO2 018176583	FTIR	Jun 18, 2025

Triad Data Available Upon Request



Signature on file

Approved for Release



69 Industrial Park Rd E, Tolland CT 06084
<https://www.environics.com/service-request>
(860) 872-1111 info@environics.com

SERVICE REPORT

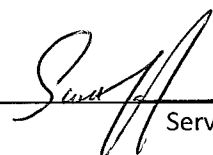
ATTN: Peter Hilty, Montrose Air Quality Services LLC

DATE OF SERVICE: 8/4/2025
MODEL NUMBER: 4040
SERIAL NUMBER: 5982

SERVICE TYPE: RECALIBRATION
NEXT CALIBRATION DUE: 8/5/2026

CONDITIONS AS OBSERVED AND WORK PERFORMED:

- Unit powers up properly.
- Unit cleaned and Purged, data verified.
- All valves checked, ok.
- Checked for any software updates
- Voltages checked – 5v, -15v, +15v, 24v.
- Battery replaced, holder added.
- Unit leak tested.
- Tested all MFC's with each port.
- Zeros on each MFC checked/adjusted.
- Spans checked/adjusted on all MFCs.
- All MFCs recalibrated.
- Verified all MFCs @ 5 standard points, passed within 0.5%
- All cables and screw/nuts tightened, ok.


Service Technician



69 Industrial Park Rd E, Tolland CT 06084
<https://www.environics.com/service-request>
(860) 872-1111 info@environics.com

ENVIRONICS FLOW CONTROLLER CALIBRATION REPORT

Unit Summary		Std Conditions		MFC Summary	
Model #:	4040	Temp:	32°F	MFC #:	1
Unit SN :	5982	Pressure:	29.92 in. Hg	MFC FS Flow:	10000
		Gas:	NITROGEN	MFC S/N:	6943300001

Flow Calibration Data is not performance data. This data is used by the system operating mode to improve the flow accuracy. The Flow Verification Data is performance data.

Flow Calibration Data

	Set Flow	True Flow
5%	500	487.074
10%	1000	986.672
20%	2000	2017.825
30%	3000	3031.575
40%	4000	4049.785
50%	5000	5062.991
60%	6000	6074.203
70%	7000	7101.241
80%	8000	8105.629
90%	9000	9159.634
100%	10000	10237.006

All values in SCCM

Flow Verification Data

	Set Flow	True Flow	% dev
99%	9900	9931.454	0.32%
85%	8500	8528.826	0.34%
55%	5500	5506.614	0.12%
25%	2500	2491.584	-0.34%
10%	1000	996.941	-0.31%

All values in SCCM

This calibration complies with ISO 17025-2005 [non-accredited] and is traceable to the National Institute of Standards and Technology (NIST). Calibration and verification are accomplished exclusively by qualified personnel following controlled procedures under ISO 9001:2015. For questions or concerns, contact Customer Service via our website, email or by phone, weekdays from 8AM - 4PM.

Verified by: Paul Starse

Date: 8/4/25



69 Industrial Park Rd E, Tolland CT 06084
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ENVIRONICS FLOW CONTROLLER CALIBRATION REPORT

Unit Summary		Std Conditions		MFC Summary	
Model #:	4040	Temp:	32°F	MFC #:	2
Unit SN :	5982	Pressure:	29.92 in. Hg	MFC FS Flow:	10000
		Gas:	NITROGEN	MFC S/N:	7053700001

Flow Calibration Data is not performance data. This data is used by the system operating mode to improve the flow accuracy. The Flow Verification Data is performance data.

Flow Calibration Data

	Set Flow	True Flow
5%	500	484.521
10%	1000	987.939
20%	2000	1994.901
30%	3000	2999.958
40%	4000	4008.480
50%	5000	5016.659
60%	6000	6041.363
70%	7000	7072.258
80%	8000	8105.069
90%	9000	9167.398
100%	10000	10242.180

All values in SCCM

Flow Verification Data

	Set Flow	True Flow	% dev
99%	9900	9940.532	0.41%
85%	8500	8537.749	0.44%
55%	5500	5503.186	0.06%
25%	2500	2498.076	-0.08%
10%	1000	1004.883	0.49%

All values in SCCM

This calibration complies with ISO 17025-2005 [non-accredited] and is traceable to the National Institute of Standards and Technology (NIST). Calibration and verification are accomplished exclusively by qualified personnel following controlled procedures under ISO 9001:2015. For questions or concerns, contact Customer Service via our website, email or by phone, weekdays from 8AM - 4PM.

Verified by: Paul Stanse

Date: 8/4/25



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ENVIRONICS FLOW CONTROLLER CALIBRATION REPORT

Unit Summary		Std Conditions		MFC Summary	
Model #:	4040	Temp:	32°F	MFC #:	3
Unit SN :	5982	Pressure:	29.92 in. Hg	MFC FS Flow:	1000
		Gas:	NITROGEN	MFC S/N:	0036718001

Flow Calibration Data is not performance data. This data is used by the system operating mode to improve the flow accuracy. The Flow Verification Data is performance data.

Flow Calibration Data

	Set Flow	True Flow
5%	50	49.507
10%	100	101.420
20%	200	205.942
30%	300	309.790
40%	400	413.270
50%	500	516.168
60%	600	619.164
70%	700	720.695
80%	800	822.750
90%	900	923.146
100%	1000	1024.879

All values in SCCM

Flow Verification Data

	Set Flow	True Flow	% dev
99%	990	992.706	0.27%
85%	850	850.927	0.11%
55%	550	550.381	0.07%
25%	250	249.944	-0.02%
10%	100	99.824	-0.18%

All values in SCCM

This calibration complies with ISO 17025-2005 [non-accredited] and is traceable to the National Institute of Standards and Technology (NIST). Calibration and verification are accomplished exclusively by qualified personnel following controlled procedures under ISO 9001:2015. For questions or concerns, contact Customer Service via our website, email or by phone, weekdays from 8AM - 4PM.

Verified by: Paul Stanse

Date: 8/4/25



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ENVIRONICS FLOW CONTROLLER CALIBRATION REPORT

Unit Summary		Std Conditions		MFC Summary	
Model #:	4040	Temp:	32°F	MFC #:	4
Unit SN :	5982	Pressure:	29.92 in. Hg	MFC FS Flow:	100
		Gas:	NITROGEN	MFC S/N:	0036720001

Flow Calibration Data is not performance data. This data is used by the system operating mode to improve the flow accuracy. The Flow Verification Data is performance data.

Flow Calibration Data

	Set Flow	True Flow
5%	5	5.092
10%	10	10.551
20%	20	21.218
30%	30	31.499
40%	40	41.393
50%	50	51.231
60%	60	60.974
70%	70	70.641
80%	80	80.461
90%	90	90.719
100%	100	101.411

All values in SCCM

Flow Verification Data

	Set Flow	True Flow	% dev
99%	99	98.561	-0.44%
85%	85	84.830	-0.20%
55%	55	54.988	-0.02%
25%	25	24.949	-0.20%
10%	10	9.959	-0.41%

All values in SCCM

This calibration complies with ISO 17025-2005 [non-accredited] and is traceable to the National Institute of Standards and Technology (NIST). Calibration and verification are accomplished exclusively by qualified personnel following controlled procedures under ISO 9001:2015. For questions or concerns, contact Customer Service via our website, email or by phone, weekdays from 8AM - 4PM.

Verified by: Paul Stangel

Date: 8/4/25

Project Information	Notes: _____
Date <u>4/23/2026</u> Project # <u>PROJ-067458</u>	
Customer / Facility <u>Howmet</u>	
Unit ID / Sample Location <u>B008/B009</u>	
Operator <u>CE</u>	

Equipment Information	
Calibration gas diluter ID/SN <u>5982</u>	Calibration expiration date <u>8/4/2026</u>
Audited dilution device (DD) ☒ DD1 ☒ DD2 ☐ DD3 ☐ DD4 ☐ DD5 ☐ DD6 ☐ DD7 ☐ DD8	
DDs used to generate cal gases ☒ DD1 ☒ DD2 ☐ DD3 ☐ DD4 ☐ DD5 ☐ DD6 ☐ DD7 ☐ DD8	
Total flow rate, LPM <u>5</u> Analyzer ID/SN <u>T-O2CO2A-002</u> Analyte O2 <u>Span value 22.05</u>	

Calibration Gas Information					
	Tag Value	Units (ppm or %)	Cylinder ID	Pressure (PSI)	Expiration Date
Dilution Level 1 Cylinder	22.05	%	CC72089	1500	1/18/2031
Dilution Level 2 Cylinder	22.05	%	CC72089	1500	1/18/2031
Direct Inject Cylinder*	11.09	%	EB0116428	200	3/3/2031

Performance Data									
	Predicted Diluted Value**	Units (ppm or %)	Analyzer Response						
			Time	Injection 1	Time	Injection 2	Time	Injection 3	Average
Dilution Level 1	11.00	%	11:11	10.89	11:17	10.89	11:23	10.84	10.87
Dilution Level 2	5.00	%	11:13	4.92	11:19	4.89	11:27	4.92	4.91
Direct Inject Gas	11.09	%	11:15	10.98	11:21	10.96	11:29	10.94	10.96

Calculations																							
<table border="1"> <tr> <th colspan="4">DI</th></tr> <tr> <th></th><th>Injection 1</th><th>Injection 2</th><th>Injection 3</th></tr> <tr> <td>Dilution Level 1</td><td>0.15%</td><td>0.15%</td><td>-0.31%</td></tr> <tr> <td>Dilution Level 2</td><td>0.20%</td><td>-0.41%</td><td>0.20%</td></tr> <tr> <td>Direct Inject</td><td>0.18%</td><td>0.00%</td><td>-0.18%</td></tr> </table>				DI					Injection 1	Injection 2	Injection 3	Dilution Level 1	0.15%	0.15%	-0.31%	Dilution Level 2	0.20%	-0.41%	0.20%	Direct Inject	0.18%	0.00%	-0.18%
DI																							
	Injection 1	Injection 2	Injection 3																				
Dilution Level 1	0.15%	0.15%	-0.31%																				
Dilution Level 2	0.20%	-0.41%	0.20%																				
Direct Inject	0.18%	0.00%	-0.18%																				
<table border="1"> <tr> <th colspan="3">DL</th></tr> <tr> <th>Dilution Level 1</th><th>Dilution Level 2</th><th>Direct Inject</th></tr> <tr> <td>1.15%</td><td>1.80%</td><td>1.17%</td></tr> </table>				DL			Dilution Level 1	Dilution Level 2	Direct Inject	1.15%	1.80%	1.17%											
DL																							
Dilution Level 1	Dilution Level 2	Direct Inject																					
1.15%	1.80%	1.17%																					
DI - Difference of each injection from the average analyzer response $DI\% = (I - R / I) * 100$ DL - Difference from predicted for each dilution level $DL\% = (P - R / P) * 100$ I - Each individual injection R - Average Response P - Predicted diluted value DI must be within 2% of the average instrument response for that dilution. DL must be within 2% of predicted value.																							

* The Direct Inject Gas must be independent of the Dilution Level gases.

** One of the Dilution Levels must be within 10% of the Direct Inject gas tag value

All injection responses must be within 2% of the average instrument response for that dilution.

For each level of dilution the average concentration output from the analyzer must be within 2% of the predicted value.

QA/QC Check: Completeness X Legibility X Accuracy X Specifications X

Checked by: SHC Team Leader: CE

001AS-QMS-WB-EPA205R1

Appendix C3 Accreditation Information / Certifications

Accredited Air Emission Testing Body

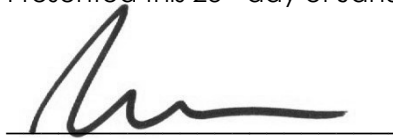
A2LA has accredited

MONTROSE AIR QUALITY SERVICES

In recognition of the successful completion of the joint A2LA and Source Evaluation Society (SES) evaluation process, this laboratory is accredited to perform testing activities in compliance with ASTM D7036:2004 - Standard Practice for Competence of Air Emission Testing Bodies.



Presented this 23rd day of January 2026.



Mr. Trace McInturff, Vice President, Accreditation Services
For the Accreditation Council
Certificate Number 3925.01
Valid to February 29, 2028

This accreditation program is not included under the A2LA ILAC Mutual Recognition Arrangement.

CERTIFICATE OF COMPLETION

Cedric Ebbeler

This document certifies that this individual has passed a comprehensive examination and is now a Qualified Individual (QI) as defined in Section 8.3 of ASTM D7036-04 for the following method(s):

Source Evaluation Society Group 3: EPA Gaseous Pollutants Instrumental Sampling Methods

Certificate Number: 011-2025-2



Tate Strickler, VP – Quality Systems

EFFECTIVE DATE: 1/29/2025

EXPIRATION DATE: 1/28/2030



MONTROSE
ENVIRONMENTAL

This is the last page of this document.

If you have any questions, please contact one of the following individuals by email or phone:

Jeremiah Hicks
Account Manager
jhicks@onterris.com
440-340-8189

Robert J. Lisy, Jr.
District Manager
rlisy@onterris.com
440-262-3760

Attachment 5

RACT Engineering Study – Combustion Source Groupings SCR

Aerospace – Cleveland Operations

As seen in the included site drawing, the 44 <10 TPY NO_x emissions units are spread out between 5 distinct plants/buildings. Those within the same plants are also not clustered in a single area for installing a common control. Additionally, the majority of the emissions units are purely fugitive sources with no existing exhaust ductwork.

The attached spreadsheet shows a breakdown of the costs for a common control device to be installed across multiple <10TPY NO_x units at the different plants/buildings on-site. The cost-estimation was performed utilizing spreadsheets presented in the U.S. EPA's Air Pollution Control Cost Manual using the U.S. EPA provided Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR). Actual values for each plant/building, 2025 annual emissions, a 90 percent control efficiency, default SCR equipment information, and a cost adjustment to 2025 dollars were used as data inputs for the estimation spreadsheet. Given the size of the facility and layout of the affected furnaces, 4 separate SCR units would need to be installed at different plants/buildings within the facility. The SCRs would result in reductions costs per ton of NO_x of \$29,510, \$77,237, \$101,794, and \$35,406 for the different plant/building furnace groupings. Beyond this annualized cost for a control device, the site would also need to spend over \$25 million to run ductwork to the SCRs and to install ductwork at the sources that are currently fugitive. This cost breakdown highlights that although the installation of shared control device for NO_x emissions are technically feasible, it is not economically feasible.

Howmet Cleveland Works - Natural Gas Fired Sources Summary - NOx Emissions

Emission Unit		Rating (MMBTU/hr)	PTE (TPY)	2022 Emissions (Tons)	2023 Emissions (Tons)	2024 Emissions (Tons)	2025 Emissions (Tons)	Notes
P100	Titanium Annealing Furnace T-8 - Bldg 206	22.2	9.53	2.11	1.82	2.22	2.59	
P125	Titanium Reheat Furnace T-9 - Bldg 206	18.6	8.00	1.79	1.54	1.88	2.20	
F027	T-10 Furnace - Bldg 206	13.98	6.00	1.34	1.16	1.41	1.65	Fugitive source
P162	27 mmBtu/hr direct gas-fired inconel preheat furnace - Bldg 206	27.0	11.59	0.00	2.24	2.72	0.00	Request limit of <10 TPY per OAC 3745-110-03(K)(16)
P177	120,000 Lbs SECO Ingot Soaking Furnace - Bldg 206	5.0	2.15	0.48	0.41	0.50	0.59	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P230	#6 Heat Treat Furnace - Bldg 206	9.0	3.86	0.86	0.75	0.91	1.06	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
F023	R&S Reheat Furnace No. 1 - Bldg 206	12.0	5.15	1.15	0.99	1.21	1.41	Fugitive source
F024	R&S Reheat Furnace No. 3 - Bldg 206	12.0	5.15	1.15	0.99	1.21	1.41	Fugitive source
F025	No. 4 Salem Furnace - Bldg 206	13.8	5.93	1.32	1.14	1.39	1.63	Fugitive source
F026	No. 5 Salem Furnace - Bldg 206	13.8	5.93	1.32	1.14	1.39	1.63	Fugitive source
P107	6005 Reheat Furnace - Bldg 210	5.36	2.30	0.51	0.44	0.54	0.63	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P154	T-12 Titanium Preheat Furnace - Bldg 210	18.6	7.99	1.78	1.54	1.88	2.19	
P054	No. 5 H.T. Dispatch Furnace	5.0	2.15	0.48	0.41	0.50	0.59	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P087	Titanium Reheat Furnace T-7	18.64	8.00	1.79	1.54	1.88	2.20	
A-Plant Totals		83.73	16.08	16.11	19.64	19.77	A-Plant Totals	

SCR 29,510 \$/ton
Ductwork \$7,988,654.40

P121 - heat treat	South Heat Treat & Age Ovens- Bldg 150 (8001)	12.98	11.37	0.00	0.00	0.00	0.00	Fugitive source
P121 - age oven	South Heat Treat & Age Ovens- Bldg 150 (8001)	13.5						Fugitive source
P122 - heat treat	North Heat Treat & Age Ovens - Bldg 150 (8002)	9.25	5.69	2.48	1.39	1.33	1.35	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P122 - age oven	North Heat Treat & Age Ovens - Bldg 150 (8002)	4.0						Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P152 - heat treat	Heat Treat Line #3- Bldg 150	13.0	7.30	3.19	1.78	1.71	1.74	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P152 - age oven	Heat Treat Line #3- Bldg 150	4.0						
P402	No. 13 Soaker Furnace - Bldg 150 (part of P102)	16.75	7.19	0.00	1.76	1.69	1.71	
S-Plant Totals		31.55	5.67	4.93	4.73	4.81	S-Plant Totals	

SCR 77,237 \$/ton
Ductwork \$5,159,158.40

P003 - heat treat	2502 Heat Treat and Age Oven - Bldg 120	3.6	3.13	0.83	0.80	0.76	0.63	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P003 - age oven	2502 Heat Treat and Age Oven - Bldg 120	3.7						Fugitive source
P004 - heat treat	2503 Heat Treat and Age Oven - Bldg 120	3.6	3.13	0.83	0.80	0.76	0.63	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P004 - age oven	2503 Heat Treat and Age Oven - Bldg 120	3.7						Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
Bldg 120 Totals		6.26	1.66	1.6	1.52	1.27	Bldg 120 Totals	

SCR 101,794 \$/ton
Ductwork \$3,246,024.00

F003	2007 Furnace - Bldg 101	1.47	0.63	0.17	0.16	0.15	0.13	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F004	2502 Furnace - Bldg 101	0.5	0.21	0.06	0.06	0.05	0.04	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F006	4504 Furnace - Bldg 101	3.5	1.50	0.00	0.39	0.36	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F007	4505 Furnace - Bldg 101	3.5	1.50	0.40	0.39	0.36	0.30	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F008	4506 Furnace - Bldg 101	1.0	0.43	0.11	0.11	0.10	0.09	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F010	12001 Furnace - Bldg 111	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source
F011	12002 Furnace - Bldg 111	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source
F012	12003 Furnace - Bldg 111	12.0	5.15	1.36	1.32	1.25	0.00	Permanently shutdown 2025
F015	12,000 Lb Reheat Furnace G-1 - Bldg 111	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source
F016	12,000 Lb Reheat Furnace G-2 - Bldg 111	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source
P434	6006 Preheat Furnace - Bldg 112A	3.6	1.55	0.44	0.57	0.52	0.39	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F018	2503 Preheat Furnace - Bldg 114	0.5	0.21	0.06	0.06	0.05	0.04	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P159	4601 Preheat Furnace - Bldg 114	3.6	1.55	0.41	0.40	0.37	0.31	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F017	2002 Preheat Furnace - Bldg 114	0.8	0.34	0.00	0.00	0.00	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F019	4509 Reheat Furnace - Bldg 114	8.0	3.44	0.90	0.88	0.83	0.70	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F020	4513 Reheat Furnace - Bldg 114	1.5	0.64	0.00	0.00	0.00	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P105	17001 Furnace - Bldg	16.8	7.21	1.90	1.85	1.74	1.46	Fugitive source
H-Plant Totals		44.96	11.25	11.47	10.78	7.16	H-Plant Totals	

SCR 35,406 \$/ton
Ductwork \$8,638,972.00

Howmet Cleveland Works - Natural Gas Fired Sources Summary - NOx Emissions

Emission Unit		Rating (MMBTU/hr)	PTE (TPY)	2022 Emissions (Tons)	2023 Emissions (Tons)	2024 Emissions (Tons)	Notes
F018	2503 Preheat Furnace - Bldg 114	0.5	0.21	0.06	0.06	0.05	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F027	T-10 Furnace - Bldg 206	13.98	6.00	1.34	1.16	1.41	Fugitive source
P054	No. 5 H.T. Despatch Furnace	5.0	2.15	0.48	0.41	0.50	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P087	Titanium Reheat Furnace T-7	18.64	8.00	1.79	1.54	1.88	
P100	Titanium Annealing Furnace T-8 - Bldg 206	22.2	9.53	2.11	1.82	2.22	
P105	17001 Furnace - Bldg	16.8	7.21	1.90	1.85	1.74	Fugitive source
P107	6005 Reheat Furnace - Bldg 210	5.36	2.30	0.51	0.44	0.54	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P121 - heat treat	South Heat Treat & Age Ovens- Bldg 150 (8001)	12.98	11.37	0.00	0.00	0.00	Fugitive source
P121 - age oven	South Heat Treat & Age Ovens- Bldg 150 (8001)	13.5					Fugitive source
P122 - heat treat	North Heat Treat & Age Ovens - Bldg 150 (8002)	9.25	5.69	2.48	1.39	1.33	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P122 - age oven	North Heat Treat & Age Ovens - Bldg 150 (8002)	4.0					Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P125	Titanium Reheat Furnace T-9 - Bldg 206	18.6	8.00	1.79	1.54	1.88	
P152 - heat treat	Heat Treat Line #3 - Bldg 150	13.0	7.30	3.19	1.78	1.71	
P152 - age oven	Heat Treat Line #3 - Bldg 150	4.0					Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P154	T-12 Titanium Preheat Furnace - Bldg 210	18.6	7.99	1.78	1.54	1.88	
P159	4601 Preheat Furnace - Bldg 114	3.6	1.55	0.41	0.40	0.37	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P162	27 mmBtu/hr direct gas-fired Inconel preheat furnace - Bldg. 206	27.0	11.59	0.00	2.24	2.72	Howmet proposes to accept an enforceable NOx potential-to-emit limitation of less than 10 tons per year for P162 to establish eligibility under OAC 3745-110-03(K)(16)
P177	120,000 Lbs SECO Ingot Soaking Furnace - Bldg 206	5.0	2.15	0.48	0.41	0.50	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P230	#6 Heat Treat Furnace - Bldg 206	9.0	3.86	0.86	0.75	0.91	Burner rating below OAC 3745-31-03(B)(1)(c) exemption
P402	No. 13 Soaker Furnace - Bldg 150 (part of P102)	16.75	7.19	0.00	1.76	1.69	
P434	6006 Preheat Furnace - Bldg 112A	3.6	1.55	0.44	0.57	0.52	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
B008	Boiler #1 - 98.8 MMBtu/hr gas fired boiler - Bldg 45	98.8	64.91	7.60	7.04	7.21	Not eligible for OAC 3745-110-03(K)(17) exemption
B009	Boiler #2 - 98.8 MMBtu/hr gas fired boiler - Bldg 45	98.8	64.91	14.19	13.10	13.51	Not eligible for OAC 3745-110-03(K)(17) exemption
F003	2007 Furnace - Bldg 101	1.47	0.63	0.17	0.16	0.15	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F004	2502 Furnace - Bldg 101	0.5	0.21	0.06	0.06	0.05	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F006	4504 Furnace - Bldg 101	3.5	1.50	0.00	0.39	0.36	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F007	4505 Furnace - Bldg 101	3.5	1.50	0.40	0.39	0.36	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F008	4506 Furnace - Bldg 101	1.0	0.43	0.11	0.11	0.10	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F010	12001 Furnace - Bldg 111	12.0	5.15	1.36	1.32	1.25	Fugitive source
F011	12002 Furnace - Bldg 111	12.0	5.15	1.36	1.32	1.25	Fugitive source
F012	12003 Furnace - Bldg 111	12.0	5.15	1.36	1.32	1.25	Permanently shutdown 2025
F015	12,000 Lb Reheat Furnace G-1 - Bldg 111	12.0	5.15	1.36	1.32	1.25	Fugitive source
F016	12,000 Lb Reheat Furnace G-2 - Bldg 111	12.0	5.15	1.36	1.32	1.25	Fugitive source
F017	2002 Preheat Furnace - Bldg 114	0.8	0.34	0.00	0.00	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F019	4509 Reheat Furnace - Bldg 114	8.0	3.44	0.90	0.88	0.83	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F020	4513 Reheat Furnace - Bldg 114	1.5	0.64	0.00	0.00	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
F023	R&S Reheat Furnace No. 1 - Bldg 206	12.0	5.15	1.15	0.99	1.21	Fugitive source
F024	R&S Reheat Furnace No. 3 - Bldg 206	12.0	5.15	1.15	0.99	1.21	Fugitive source
F025	No. 4 Salem Furnace - Bldg 206	13.8	5.93	1.32	1.14	1.39	Fugitive source
F026	No. 5 Salem Furnace - Bldg 206	13.8	5.93	1.32	1.14	1.39	Fugitive source
P003 - heat treat	2502 Heat Treat and Age Oven - Bldg 120	3.6	3.13	0.83	0.80	0.76	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P003 - age oven	2502 Heat Treat and Age Oven - Bldg 120	3.7					Fugitive source
P004 - heat treat	2503 Heat Treat and Age Oven - Bldg 120	3.6					Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption
P004 - age oven	2503 Heat Treat and Age Oven - Bldg 120	3.7					Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates ($\pm 30\%$) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial ▼

What type of fuel does the unit burn?

Natural Gas ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

14.6 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

25,396,757 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

690 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable ▼

Enter the sulfur content (%S) =

percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☐ Method 1
☐ Method 2
☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the boiler operates (t_{plant})

365 days

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Inlet NO _x Emissions (NO _{x,in}) to SCR	0.098039216 lb/MMBtu
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.009803922 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of empty catalyst layers (R _{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate (Q _{fluegas}) (Enter "UNK" if value is not known)	55000 acfm

Estimated operating life of the catalyst (H _{catalyst})	24,000 hours
Estimated SCR equipment life	25 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650 °F
Base case fuel gas volumetric flow rate factor (Q _{fuel})	14.6 ft ³ /min-MMBtu/hour

Concentration of reagent as stored (C _{stored})	50 percent*
Density of reagent as stored (ρ _{stored})	71 lb/cubic feet*
Number of days reagent is stored (t _{storage})	14 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Select the reagent used Urea ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2025
CEPCI for 2025	829.3 Enter the CEPCI value for 2025 541.7 2016 CEPCI
Annual Interest Rate (i)	6.75 Percent
Reagent (Cost _{reag})	1.660 \$/gallon for 50% urea*
Electricity (Cost _{elect})	0.0676 \$/kWh
Catalyst cost (CC _{replace})	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)
Operator Labor Rate	35.00 \$/hour (including benefits)
Operator Hours/Day	4.00 hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* \$1.66/gallon is a default value for 50% urea. User should enter actual value, if known.

* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.

* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_cost_development_methodology_chapter_5_attachment_5-3.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	15	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	125,388,235	scf/Year
Actual Annual fuel consumption (Mactual) =		25,396,757	scf/Year
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.82	
Total System Capacity Factor (CF_{total}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.203	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	1774	hours
NO _x Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent
NO _x removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	1.29	lb/hour
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	1.14	tons/year
NO _x removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	55,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	947.36	/hour
Residence Time	$1/V_{space}$	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$		
Elevation Factor (ELEV) =	$14.7\ psia/P =$	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightssystemsgov.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / ((1 + \text{interest rate})^Y - 1)$, where $Y = H_{catalyst} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.3118	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times (T_{adj}/N_{scr})$	58.06	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16\text{ft/sec} \times 60\text{ sec/min})$	57	ft ²

Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	1	feet
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SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	66	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	8.1	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	42	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft ³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	2	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	0	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i= Interest Rate	0.0839

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = (0.1 x QB) for industrial boilers.	7.51	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =

\$1,258,826

in 2025 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =

\$9,112 in 2025 dollars

Indirect Annual Costs (IDAC) =

\$107,224 in 2025 dollars

Total annual costs (TAC) = DAC + IDAC

\$116,336 in 2025 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =

$$0.005 \times TCI =$$

\$6,294 in 2025 dollars

Annual Reagent Cost =

$$m_{sol} \times Cost_{reag} \times t_{op} =$$

\$548 in 2025 dollars

Annual Electricity Cost =

$$P \times Cost_{elect} \times t_{op} =$$

\$900 in 2025 dollars

Annual Catalyst Replacement Cost =

\$1,370 in 2025 dollars

$$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$$

Direct Annual Cost =

\$9,112 in 2025 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =

$$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$$

\$1,609 in 2025 dollars

Capital Recovery Costs (CR)=

$$CRF \times TCI =$$

\$105,615 in 2025 dollars

Indirect Annual Cost (IDAC) =

$$AC + CR =$$

\$107,224 in 2025 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =

\$116,336 per year in 2025 dollars

NOx Removed =

1 tons/year

Cost Effectiveness =

\$101,794 per ton of NOx removed in 2025 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial ▼

What type of fuel does the unit burn?

Natural Gas ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

194.98 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

490,616,000 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

690 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable ▼

Enter the sulfur content (%S) =

percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☐ Method 1
☐ Method 2
☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions ($NO_{x_{in}}$) to SCR	0.098039216 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions ($NO_{x_{out}}$) from SCR	0.009803922 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	0.525	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 0.525 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	264000 acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	194.98 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

Concentration of reagent as stored (C_{stored})	50 percent*	*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14 days	

Select the reagent used

Urea

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2025	
CEPCI for 2025	829.3 Enter the CEPCI value for 2025	541.7 2016 CEPCI
Annual Interest Rate (i)	6.75 Percent	CEPCI = Chemical Engineering Plant Cost Index
Reagent (Cost _{reag})	1.660 \$/gallon for 50% urea*	* \$1.66/gallon is a default value for 50% urea. User should enter actual value, if known.
Electricity (Cost _{elect})	0.0676 \$/kWh	* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost (CC _{replace})	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	35.00 \$/hour (including benefits)	
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =
Administrative Charges Factor (ACF) =

0.005
0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	195	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	1,674,534,118	scf/Year
Actual Annual fuel consumption (Mactual) =		490,616,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.293	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	2567	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	17.20	lb/hour
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	22.08	tons/year
NO _x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	264,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	340.50	/hour
Residence Time	$1/V_{space}$	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$		
Elevation Factor (ELEVf) =	14.7 psia/P =	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3118	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	775.33	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	275	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	316	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	17.8	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	45	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_B \times EF \times \text{SRF} \times \text{MW}_R)/\text{MW}_{\text{NOx}} =$	12	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}}/\text{Csol} =$	24	lb/hour
	$(m_{\text{sol}} \times 7.4805)/\text{Reagent Density}$	2	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24)/\text{Reagent Density} =$	900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1 =$ Where n = Equipment Life and i = Interest Rate	0.0839

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where $A = (0.1 \times Q_B)$ for industrial boilers.	100.26	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =

\$6,786,248

in 2025 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$80,203 in 2025 dollars
Indirect Annual Costs (IDAC) =	\$571,306 in 2025 dollars
Total annual costs (TAC) = DAC + IDAC	\$651,509 in 2025 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$33,931 in 2025 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$10,585 in 2025 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$17,395 in 2025 dollars
Annual Catalyst Replacement Cost =	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	\$18,292 in 2025 dollars
Direct Annual Cost =		\$80,203 in 2025 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$1,940 in 2025 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$569,366 in 2025 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$571,306 in 2025 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$651,509 per year in 2025 dollars
NOx Removed =	22 tons/year
Cost Effectiveness =	\$29,510 per ton of NOx removed in 2025 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial ▼

What type of fuel does the unit burn?

Natural Gas ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

104.77 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

269,831,843 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

690 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable ▼

Enter the sulfur content (%S) =

percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

☐ Method 1

☐ Method 2

☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.098039216 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.009803922 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	0.525	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 0.525 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	264000 acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	104.77 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

Concentration of reagent as stored (C_{stored})	50 percent*	*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14 days	

Select the reagent used

Urea

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2025				
CEPCI for 2025	829.3	Enter the CEPCI value for 2025	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	6.75	Percent			
Reagent (Cost _{reag})	1.660	\$/gallon for 50% urea*			* \$1.66/gallon is a default value for 50% urea. User should enter actual value, if known.
Electricity (Cost _{elect})	0.0676	\$/kWh			* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost (CC _{replace})	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)			* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	35.00	\$/hour (including benefits)			
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	105	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	899,789,412	scf/Year
Actual Annual fuel consumption (Mactual) =		269,831,843	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.300	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	2627	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	9.24	lb/hour
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	12.14	tons/year
NO _x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	264,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	633.68	/hour
Residence Time	$1/V_{space}$	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$		
Elevation Factor (ELEVf) =	14.7 psia/P =	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightssystemsgrc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3118	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	416.61	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	275	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	316	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	17.8	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	43	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_B \times EF \times \text{SRF} \times \text{MW}_R)/\text{MW}_{\text{NOx}} =$	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}}/C_{\text{sol}} =$	13	lb/hour
	$(m_{\text{sol}} \times 7.4805)/\text{Reagent Density}$	1	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24)/\text{Reagent Density} =$	500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1 =$ Where n = Equipment Life and i = Interest Rate	0.0839

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where $A = (0.1 \times Q_B)$ for industrial boilers.	53.87	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =

\$4,532,003

in 2025 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$47,877 in 2025 dollars
Indirect Annual Costs (IDAC) =	\$382,040 in 2025 dollars
Total annual costs (TAC) = DAC + IDAC	\$429,917 in 2025 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$22,660 in 2025 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$5,822 in 2025 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$9,567 in 2025 dollars
Annual Catalyst Replacement Cost =	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	\$9,829 in 2025 dollars
Direct Annual Cost =		\$47,877 in 2025 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$1,805 in 2025 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$380,235 in 2025 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$382,040 in 2025 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$429,917 per year in 2025 dollars
NOx Removed =	12 tons/year
Cost Effectiveness =	\$35,406 per ton of NOx removed in 2025 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial ▼

What type of fuel does the unit burn?

Natural Gas ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

73.48 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

96,110,800 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

690 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable ▼

Enter the sulfur content (%S) =

percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

☐ Method 1

☐ Method 2

☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the boiler operates (t_{plant})

365 days

Inlet NO_x Emissions (NO_{x,in}) to SCR

0.098039216 lb/MMBtu

Outlet NO_x Emissions (NO_{x,out}) from SCR

0.009803922 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)

24,000 hours

Estimated SCR equipment life

25 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})

50 percent*

Density of reagent as stored (ρ_{stored})

71 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$)

14 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$)
(Enter "UNK" if value is not known)

UNK Cubic feet

Flue gas flow rate ($Q_{fluegas}$)

(Enter "UNK" if value is not known)

100000 acfm

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

73.48 ft³/min-MMBtu/hour

Select the reagent used

Urea

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year

2025

CEPCI for 2025

829.3 Enter the CEPCI value for 2025

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

6.75 Percent

Reagent (Cost_{reag})

1.660 \$/gallon for 50% urea*

* \$1.66/gallon is a default value for 50% urea. User should enter actual value, if known.

Electricity (Cost_{elect})

0.0676 \$/kWh

* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.

Catalyst cost (CC_{replace})

\$/cubic foot (includes removal and disposal/regeneration of existing
227.00 catalyst and installation of new catalyst

* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate

35.00 \$/hour (including benefits)

Operator Hours/Day

4.00 hours/day*

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.005

Administrative Charges Factor (ACF) =

0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	73	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	631,063,529	scf/Year
Actual Annual fuel consumption (Mactual) =		96,110,800	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.152	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	1334	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	6.48	lb/hour
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	4.32	tons/year
NO _x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	100,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	342.24	/hour
Residence Time	$1/V_{space}$	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$		
Elevation Factor (ELEVf) =	14.7 psia/P =	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3118	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	292.19	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$Q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	104	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	120	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	10.9	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	45	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_B \times EF \times \text{SRF} \times \text{MW}_R)/\text{MW}_{\text{NOx}} =$	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}}/\text{Csol} =$	9	lb/hour
	$(m_{\text{sol}} \times 7.4805)/\text{Reagent Density}$	1	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24)/\text{Reagent Density} =$	400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1 =$ Where n = Equipment Life and i = Interest Rate	0.0839

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where $A = (0.1 \times Q_B)$ for industrial boilers.	37.78	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =

\$3,598,704

in 2025 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$30,368 in 2025 dollars
Indirect Annual Costs (IDAC) =	\$303,680 in 2025 dollars
Total annual costs (TAC) = DAC + IDAC	\$334,048 in 2025 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$17,994 in 2025 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$2,074 in 2025 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$3,408 in 2025 dollars
Annual Catalyst Replacement Cost =	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	\$6,894 in 2025 dollars
Direct Annual Cost =		\$30,368 in 2025 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$1,749 in 2025 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$301,931 in 2025 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$303,680 in 2025 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$334,048 per year in 2025 dollars
NOx Removed =	4.32 tons/year
Cost Effectiveness =	\$77,237 per ton of NOx removed in 2025 dollars

Attachment 6

Engineered Groupings NOx Emissions 2022-2025

Howmet Cleveland Works - Natural Gas Fired Sources Summary - NOx Emissions

Emission Unit	Rating (MMBTU/hr)	PTE (TPY)	2022 Emissions (Tons)	2023 Emissions (Tons)	2024 Emissions (Tons)	2025 Emissions (Tons)	Notes	Stack Height (ft)	Stack Diameter (ft)	Max Flow (ACFM)	Avg. Flow (ACFM)	Max Temp (F)	Avg. Temp (F)	2022 Daily Avg Emissions (lb/day)	2023 Daily Avg Emissions (lb/day)	2024 Daily Avg Emissions (lb/day)	2025 Daily Avg Emissions (lb/day)
F018	0.5	0.21	0.06	0.06	0.05	0.04	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.33	0.33	0.27	0.24
F027	13.98	6.00	1.34	1.16	1.41	1.65	Fugitive source	NA	NA	NA	NA	NA	NA	7.34	6.36	7.70	9.03
P054	5.0	2.15	0.48	0.41	0.50	0.59	Burner rating below OAC 3745-31-03(B)(1)(c) exemption	58.8	2.98	3,950	3,950	1800	1800	2.63	2.25	2.73	3.23
P087	18.64	8.00	1.79	1.54	1.88	2.20		102.4	3.48	4,000	4,000	1800	1800	9.81	8.44	10.27	12.04
P100	22.2	9.53	2.11	1.82	2.22	2.59		65.67	4	3,000	3,000	1800	1800	11.56	9.97	12.13	14.20
P105	16.8	7.21	1.90	1.85	1.74	1.46	Fugitive source	NA	NA	NA	NA	NA	NA	10.41	10.14	9.51	8.01
P107	5.36	2.30	0.51	0.44	0.54	0.63	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	2.79	2.41	2.95	3.46
P121 - heat treat	12.98	11.37	0.00	0.00	0.00	0.00	Fugitive source	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
P121 - age oven	13.5						Fugitive source	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
P122 - heat treat	9.25	5.69	2.48	1.39	1.33	1.35	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	13.59	7.62	7.27	7.42
P122 - age oven	4.0						Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
P125	18.6	8.00	1.79	1.54	1.88	2.20		102.4	3.5	4,041	4,041	1800	1800	9.81	8.44	10.27	12.04
P152 - heat treat	13.0	7.30	3.19	1.78	1.71	1.74		40						17.48	9.75	9.34	9.52
P152 - age oven	4.0						Burner rating below OAC 3745-31-03(B)(1)(c) exemption	40						0.00	0.00	0.00	0.00
P154	18.6	7.99	1.78	1.54	1.88	2.19		60.2	5					9.75	8.44	10.27	12.01
P159	3.6	1.55	0.41	0.40	0.37	0.31	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	2.25	2.19	2.02	1.72
P162	27.0	11.59	0.00	2.24	2.72	0.00	Request limit of <10 TPY per OAC 3745-110-03(K)(16)	110.86	8.99	9,900	9,000	1900	1770	0.00	12.27	14.86	0.00
P177	5.0	2.15	0.48	0.41	0.50	0.59	Burner rating below OAC 3745-31-03(B)(1)(c) exemption			25,000	25,000	175	175	2.63	2.25	2.73	3.23
P230	9.0	3.86	0.86	0.75	0.91	1.06	Burner rating below OAC 3745-31-03(B)(1)(c) exemption							4.71	4.11	4.97	5.81
P402	16.75	7.19	0.00	1.76	1.69	1.71				24,885	24,885	127	127	0.00	9.64	9.23	9.38
P434	3.6	1.55	0.44	0.57	0.52	0.39	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	2.41	3.12	2.84	2.12
B008	98.8	64.91	7.60	7.04	7.21	7.50	Not eligible for OAC 3745-110-03(K)(17) exemption	49.75	3.67	40,000	32,000	350	310	41.64	38.58	39.40	41.08
B009	98.8	64.91	14.19	13.10	13.51	14.13	Not eligible for OAC 3745-110-03(K)(17) exemption	49.75	3.67	40,000	32,000	350	310	77.75	71.78	73.83	77.41
F003	1.47	0.63	0.17	0.16	0.15	0.13	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.93	0.88	0.82	0.70
F004	0.5	0.21	0.06	0.06	0.05	0.04	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.33	0.33	0.27	0.24
F006	3.5	1.50	0.00	0.39	0.36	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.00	2.14	1.97	0.00
F007	3.5	1.50	0.40	0.39	0.36	0.30	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	2.19	2.14	1.97	1.67
F008	1.0	0.43	0.11	0.11	0.10	0.09	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.60	0.60	0.55	0.48
F010	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source	NA	NA	NA	NA	NA	NA	7.45	7.23	6.83	5.72
F011	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source	NA	NA	NA	NA	NA	NA	7.45	7.23	6.83	5.72
F012	12.0	5.15	1.36	1.32	1.25	0.00	Permanently shutdown 2025	NA	NA	NA	NA	NA	NA	7.45	7.23	6.83	0.00
F015	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source	NA	NA	NA	NA	NA	NA	7.45	7.23	6.83	5.72
F016	12.0	5.15	1.36	1.32	1.25	1.04	Fugitive source	NA	NA	NA	NA	NA	NA	7.45	7.23	6.83	5.72
F017	0.8	0.34	0.00	0.00	0.00	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
F019	8.0	3.44	0.90	0.88	0.83	0.70	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	4.93	4.82	4.54	3.81
F020	1.5	0.64	0.00	0.00	0.00	0.00	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
F023	12.0	5.15	1.15	0.99	1.21	1.41	Fugitive source	NA	NA	NA	NA	NA	NA	6.30	5.42	6.61	7.75
F024	12.0	5.15	1.15	0.99	1.21	1.41	Fugitive source	NA	NA	NA	NA	NA	NA	6.30	5.42	6.61	7.75
F025	13.8	5.93	1.32	1.14	1.39	1.63	Fugitive source	NA	NA	NA	NA	NA	NA	7.23	6.25	7.60	8.91
F026	13.8	5.93	1.32	1.14	1.39	1.63	Fugitive source	NA	NA	NA	NA	NA	NA	7.23	6.25	7.60	8.91
P003 - heat treat	3.6	3.13	0.83	0.80	0.76	0.63	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	4.55	4.38	4.15	3.48
P003 - age oven	3.7						Fugitive source	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
P004 - heat treat	3.6	3.13	0.83	0.80	0.76	0.63	Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	4.55	4.38	4.15	3.48
P004 - age oven	3.7						Fugitive source, burner rating below OAC 3745-31-03(B)(1)(c) exemption	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00
Totals			56.45	54.25	57.39	55.11	Totals							309.32	297.26	313.61	301.98
Totals less boilers B008/B009			34.66	34.11	36.67	33.49	Totals less boilers B008/B009							189.92	186.90	200.38	183.50

Attachment 7

RACT Implementation Schedule 2026-2028 Gantt Chart

[illegible]

Public Notice
Ohio Environmental Protection Agency
Draft State Implementation Plan
NO_x Reasonably Available Control Technology (RACT)
for Howmet Aerospace Inc. (Facility ID 1318170314)

Cuyahoga County

Notice is hereby given that the Director of the Ohio Environmental Protection Agency, (Ohio EPA) is submitting to the United States Environmental Protection Agency (U.S. EPA) Reasonably Available Control Technology (RACT) for Howmet Aerospace Inc. (Facility ID 1318170314) for approval into Ohio's state implementation plan (SIP) for the 2015 ozone National Ambient Air Quality Standard (NAAQS).

On March 17, 2025, Ohio submitted a revision to Ohio's SIP to address RACT requirements for the 2015 8-hour ozone NAAQS. As noted in this submittal, OAC rule 3745-110-03(J) requires facilities that have the potential to emit of fifty tons per year or more, but less than one hundred tons per year of nitrogen oxides (NO_x) and are located in nonattainment counties to submit a RACT study if they are not subject to the NO_x RACT limits in OAC rule 3745-110-03(A) to OAC rule 3745-110-03(G), the exemptions under OAC rule 3745-110-03(K), or that are subject to the aforementioned presumptive NO_x RACT limits but claim that they are technically infeasible or economically unreasonable to achieve.

Ohio is now submitting source-specific NO_x RACT for Howmet Aerospace Inc. (Facility ID 1318170314) for approval into Ohio's SIP. This facility is located in the Cleveland 2015 ozone maintenance area and has no prior existing source-specific RACT established in OAC rule 3745-110-03.

The updated RACT Study was submitted per OAC rule 3745-110-03(J). Ohio has determined that the updated RACT study, along with supplemental information submitted subsequently, is sufficient to justify implementing the installation of Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR) at emissions unit B009 and B009 proposed by the facility to act as RACT under the 2015 ozone standard.

Ohio EPA is now requesting approval of the proposed RACT for Howmet Aerospace Inc. into Ohio's SIP.

Ohio EPA is seeking public comment to satisfy U.S. EPA requirements for public involvement in SIP related activities in accordance with 40 CFR 51.102.

The public comment period will run until September 7, 2026. Written comments should be submitted at: <https://ohioepa.commentinput.com> - Search by entering the permit # (P0140885) in the "Search Projects" search box.

A public hearing on this action may be requested by contacting Kathryn Jobe at 614-728-0671 or kathryn.jobe@epa.ohio.gov no later than 30 days from the draft public notice. If a public hearing is requested, a new notification will be published to identify the time and location of the public hearing. The public hearing will be held at least 30 days after the date of the new notification.

All interested persons are entitled to comment on these changes. All comments submitted to the above address by the close of business September 7, 2026. will be considered by Ohio EPA prior to final action on this action. Written statements submitted after this time period may be considered as time and circumstances permit but will not be part of the official record.

Questions or comments about this document should be directed to Kathryn Jobe at 614-728-0671 or kathryn.jobe@epa.ohio.gov.



DATE

Ms. Anne Vogel
Regional Administrator
U.S. EPA, Region 5
77 West Jackson Blvd.
Chicago, Illinois 60604

Re: Revision to Ohio's Reasonably Available Control Technology (RACT) State Implementation Plan for the 2015 Ozone National Ambient Air Quality Standards – Source-Specific NO_x RACT for Howmet Aerospace Inc. (Facility ID 1318170314)

Dear Administrator Vogel:

On March 17, 2025, Ohio submitted a revision to Ohio's State Implementation Plan (SIP) to address Reasonably Available Control Technology (RACT) requirements for the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) for areas classified as serious. As noted in this submittal, Ohio EPA adopted requirements in OAC rule 3745-110-04 for facilities in the nonattainment areas that emit fifty hundred tons per year or more, but less than one hundred tons per year of NO_x from sources not controlled by the presumptive NO_x RACT limits in OAC rule 3745-110-03(A) to OAC rule 3745-110-03(G), the exemptions under OAC rule 3745-110-03(K), or that are subject to the aforementioned presumptive NO_x RACT limits but claim that they are technically infeasible or economically unreasonable to achieve to submit an updated RACT study within one year of the effective date of the rule. Upon review of the RACT study, Ohio EPA evaluated if the RACT proposed by the facility is appropriate to satisfy RACT requirements under the 2015 ozone standard.

Ohio is now submitting source-specific NO_x RACT for Howmet Aerospace Inc. (Facility ID 1318170314) for approval into Ohio's SIP. This facility is located in the Cleveland 2015 ozone maintenance area and has no prior existing source-specific RACT established in OAC rule 3745-110-03.

The updated NO_x RACT Study was submitted per OAC rule 3745-110-03. Ohio has determined that the updated RACT study, along with supplemental information submitted subsequently, is sufficient to justify implementing the installation of Low-NO_x Burners (LNB/ULNB) with integrated Flue Gas Recirculation (FGR) for emissions units B008 and B009 proposed by the facility to act as RACT under the 2015 ozone standard. The RACT study is provided in Appendix A, and the permit that incorporated RACT is provided as Appendix B. Within the permit, we have highlighted the terms and

conditions associated with RACT and request only those provisions are subject to this SIP revision request. Appendix C provides the permit strategy write-up for the permit.

Ohio held a public comment period on Ohio's RACT determination from August 6 to September 7, 2026. Appendix D contains the public notice. **[Ohio's response to comments received during the public comment period is in Appendix E/No comments were received during the public comment period].**

This SIP does not include the relaxation of any existing requirements and therefore will not interfere with the attainment or maintenance of the NAAQS in accordance with section 110(l) of the CAA.

Ohio EPA is now requesting approval of the proposed RACT for Howmet Aerospace Inc. into Ohio's SIP.

Ohio EPA is submitting this SIP via U.S. EPA's State Planning Electronic Collaboration System (SPeCS). If you have questions, please contact Jennifer Van Vlerah in our Division of Air Pollution Control at (614) 644-3696.

Sincerely,

John Logue
Director

Cc: Bob Hodanbosi, Chief, Division of Air Pollution Control, Ohio EPA

Enclosures