COMMONWEALTH OF PENNSYLVANIA
Department of Environmental Protection
October 30, 2025

Subject: Significant Operating Permit Modification
Title V Operating Permit 23-00038 – RACT III Alternate Proposal
Delaware County Regional Water Quality Control Authority
(DELCORA) - Western Regional Treatment Plant
100 East Fifth Street, P.O. Box 999
Chester, PA 19016-0999
APS No. 491180; Authorization No. 1517799; PF ID No.: 482687

To: Jillian Gallagher
Environmental Program Manager
Air Quality Program

From: James A. Beach, P.E.
Environmental Engineer Manager
Air Quality Program

1. **Application and Background Information**:

Trinity Consultants, on behalf of the Delaware County Regional Water Quality Control Authority (DELCORA) for their Western Regional Water Treatment Facility in the City of Chester, Delaware County, submitted a Significant Operating Permit Modification Application on February 28, 2025, to DELCORA's Title V Operating Permit. The application was submitted to provide an Alternative Reasonably Available Control Technology III Nitrogen Oxide Proposal (Alternative RACT III Proposal) in accordance with 25 Pa. Code § 129.114(a) for their Two (2) Sewage Sludge Incinerators. The requirements of RACT III (25 Pa. Code §§ 129.111 – 129.115) are applicable to facilities that emit greater than or equal to 50 tons per year (tpy) nitrogen oxides (NOx) and/or greater than or equal to 50 tpy volatile organic compounds (VOC) in a region designated as Serious Non-attainment for Ozone Emissions under RACT III that commenced operation before August 3, 2018. DELCORA is subject to the RACT III requirements for NOx because the potential to emit NOx is greater than 50 tpy.

Potential-to-emit VOC emissions for the facility is currently limited in the Title V Operating Permit to 49.1 tons/year. Prior to August 3, 2018, the facility was limited to 49.9 tons VOC per year. RACT III requirements do not apply to VOC emissions from DELCORA.

The RACT standards were created to satisfy the 2015 National Ambient Air Quality Standards (NAAQS) for ozone. The NAAQS are established by the U.S Environmental Protection Agency (EPA) as the maximum concentrations in the atmosphere for specific air contaminants to protect public health and welfare.

Table 1 below provides information on the date that tasks were completed in the processing of this application.

Table 1. Pertinent Information for the Processing of the Application

Action Item	Date
Date Application Received	2/28/2025
Date Application Deemed Complete and Technically Adequate	3/7/2025
Date Technical Deficiency Sent	10/9/2025
Date Response to Technical Deficiency Received	10/17/2025
Date Draft Sent to Company and U.S. EPA	11/3/2025
Date Notice Published in *The Pennsylvania Bulletin*	11/1/2025
Dates Published in the (insert name of newspaper here)	
Public Hearing Date for Revisions to the PA State Implementation Plan (SIP)	12/2/2025
Date Comments Received from Public	
Date Comments Received from U.S. EPA	
Date Comments Received from the Company	

Using the interactive map found on the Pennsylvania Environmental Justice Mapping and Screening Tool (PennEnviroScreen), the facility is located in (or is located within ½ mile of) an Environmental Justice (EJ) area. This significant operating permit modification application was considered an opt-in application in accordance with Appendix C of the Environmental Justice Policy (Document No. 015-0501-002). The Department of Environmental Protection (DEP) has developed a Plain Language Summary of this action to provide more information to the public; flyers for the public hearing are being distributed in community meetings announcing the application and the public hearing for revision of the SIP; the application, permit, and technical review memo were uploaded to the DEP website; and the public hearing will be held at the Chester City Hall on December 2, 2025.

Application Completeness and Technical Adequacy Checklist

Per 25 Pa. Code § 129.114(d)(1), the proposal/application was timely and was submitted on February 28, 2025. A revised application was submitted on June 24, 2025.

As per 25 Pa. Code § 129.114(d)(3-6), Table 2 shows the proposals/applicability expressed in the application.

Table 2: Alternate RACT demonstration expressed in the application

Requirements	Applicability/Completion
RACT proposal in accordance with the procedures in 25 Pa. Code § 129.92(a)(1) — (5) and (b).	• Yes • Most of the information is in Section 2 of the proposal. Attachment 3 to this memo has a revised Top-down analysis for RACT III.
RACT proposal schedule for completing implementation of the RACT requirement or RACT emission	• No schedule required. • Alternate RACT III Proposal is to operate as they currently do (no changes in operation)
Interim dates in the schedule, if needed, required under 25 Pa. Code § 129.114(d)(4) for the: (i) Issuance of purchase orders. (ii) Start and completion of process, technology and control technology changes. (iii) Completion of compliance testing.	• Not Applicable • Company is continuing to use their current control technology.
RACT proposal methods for demonstrating compliance and recordkeeping and reporting requirements in accordance with 25 Pa. Code §129.115 (relating to written notification, compliance demonstration and recordkeeping and reporting requirements) for each air contamination source included in the RACT proposal.	• Yes • See Section 4 of the application.

2. NOx Sources and Emissions

Table 3 summarizes the sources of NOx from DELCORA. Table 3 below also provides the potential and average actual emissions of NOx over the last five (5) years (2020 – 2024). See Attachment 1 for more details.

Table 3. Facility NOx Emitting Sources with Potential and Average Annual Emissions of NOx over the Past 5 Years

Source Name	Source ID No.	Potential NOx Emissions (tpy)[b]	Average Actual NOx Emissions (tpy)[c]
B-2 Boilers (2 total)	031	0.54 (each boiler)	0.47 combined
B-3 Boilers (3 total)	032	0.64 (each boiler)	
Sewage Sludge Incinerator 1	001	Combined 65.7[a] (15.0 lbs/hr each)	26.24
Sewage Sludge Incinerator 2	002		33.15

[a] Permit limit for NOx on the Sewage Sludge Incinerators.

[b] For the Boilers (Source ID Nos. 031 and 032, AP-42 Emissions Factors (Vol. 1, Chapter 1.4) were used to calculate emissions (see Attachment 1 for details).

[c] The average actual emissions of NOx over the last five (5) years (2020 – 2024)

The boilers in Source ID Nos. 031 and 032 were installed after August 3, 2018, which was the cutoff date for RACT III applicability. For each individual boiler, their emissions are below 1 tpy NOx. Source ID Nos. 031 and 032 are exempt from RACT III requirements per 25 Pa. Code §§ 129.111(a) and (c).

3. Summary of the Facility's Alternate RACT III Proposal

Per the requirements of 25 Pa. Code § 129.114(d)(1), DELCORA submitted their proposal for compliance with RACT III and performed a top-down analysis of various NOx control strategies that may be applied to their sewage sludge incinerators. In this top-down analysis, DELCORA's consultant performed the following steps:

Step 1: After review of the RACT/BACT/LAER Clearinghouse (RBLC), the following control techniques were identified as available for use for large scale combustors, which may include availability to sewage sludge incinerators:

- Selective Catalytic Reduction (SCR)
- Selective Non-catalytic Reduction (SNCR)
- Flue Gas Recirculation (FGR)
- Good Combustion Practices/Proper Incinerator Operation
- Low NOx Burners

Note that other technologies were reviewed (NOx Scrubber, Staged Air Combustion, and Reburn), but none of these controls have been used on sewage sludge incinerators in the past. Since they were not used in sewage sludge incinerators, these controls have been deemed technically infeasible.

Step 2: Trinity Consultants proceeded to review each of the control technologies to determine if they would be technically feasible to use for controlling NOx from the sewage sludge incinerators and eliminate the technically infeasible options. Table 4 (next page) summarizes the results of their findings.

Step 3: The technically feasible options were then ranked by their control effectiveness. Since DELCORA is already utilizing good combustion practices/proper incinerator operation (baseline control for NOx from the sewage sludge incinerators), the technical feasibility of operating the sewage sludge incinerators with FGR was the only option that required review for control effectiveness. FGR was cited as having a 20 to 40% control efficiency in the reduction of NOx emissions from a study done by Chavond-Barry Engineering Corp (see Attachment 3).

Step 4: In the proposal, the calculation of cost analysis did not appear to be annualized for comparison to RACT III criteria from 25 Pa. Code § 127.114(i)(1)(i) of $7,500/ton NOx emissions reduced. A technical deficiency letter requesting this cost analysis to be annualized was sent to DELCORA on October 9, 2025 (see Attachment 2). Trinity Consultants responded on behalf of DELCORA with the corrected cost analysis on October 17, 2025 (see Attachment 3). The general trend is that Sewage Sludge Incinerator 2 (Source ID No. 002) has a higher throughput than Sewage Sludge Incinerator 1 (Source ID No. 001). At

a. an estimated 38% control efficiency for NOx
b. an interest rate of 7.25% annually for a lifespan of the FGR of 25 years,
c. the cost effectiveness was calculated to be:

- Sewage Sludge Incinerator 1 (Source ID No. 001) = <u>$12,230.69/ton NOx Reduced</u> (NOx reduced by 8.27 tpy).
- Sewage Sludge Incinerator 2 (Source ID No. 002) = <u>$8,315.79/ton NOx Reduced</u> (NOx reduced by 12.17 tpy).

DELCORA found that the use of FGR would not be cost effective in reducing NOx emissions from the Sewage Sludge Incinerators, making FGR economically infeasible for Alternate RACT III compliance.

Step 5: ***DELCORA proposed that their Alternate RACT III Plan is Good Combustion Practices/Proper Incinerator Operation.***

Trinity Consultants defined good combustion practices/proper incinerator operation in the Alternate RACT III Proposal as follows:

"Generally, emissions are minimized when the furnace temperature is kept at the lower end of the desired range and when the distribution of air at the air and fuel injection zones is controlled. Ideally, maintaining a low-oxygen condition near the fuel injection points approaches an off-stoichiometric staged combustion process.

A certain amount of air is required to provide sufficient oxygen to burn all of the fuel. However, any excess air contributes to increased NOx emissions in two ways: 1) Excess air effectively increases the amount of air that must be heated, resulting in decreased fuel efficiency and higher NOx emissions, and 2) Excess are provides greater amounts of oxygen in the combustion zone that will lead to greater amounts of thermal NOx formation. By minimizing the amount of air used in the combustion process while maintaining proper furnace operation, the formation of NOx can be reduced."

Table 4. Results of the Facility's Findings for Technical Feasibility of Options for Controlling NOx from the Sewage Sludge Incinerators

Control Technology	Technically Feasible	Reason
Selective Catalytic Reduction (SCR)	No	Particulate matter (PM) in exhaust from the sewage sludge incinerator may clog catalyst. Methods to remove PM lower temperature below catalyst activity.
Selective Non-catalytic Reduction (SNCR)	No	Temperature of exhaust from the sewage sludge incinerator is below the optimum temperature range for the reaction to take place between NOx and urea.
Flue Gas Recirculation (FGR)	Yes	There is a memo from Chavond-Barry Engineering Corp. reviewing the use of FGR for prevention of slagging in the incinerator. There is an additional benefit that some NOx reductions (20 – 40%) could be seen as well.
Good Combustion Practices/ Proper Incinerator Operation	Yes	Currently utilizing this method in operation of the sewage sludge incinerators.
Low NOx Burners	No	Increase in excess air flow required (50 – 100% more excess air is required) by these types of burners to complete the combustion of sewage sludge exceeds the ideal air to fuel ratio for the effective use of low NOx burners. Technology has not been applied to sewage sludge incinerators.

4. DEP's Review of the Alternate RACT III Proposal

DEP concurs with the assessment in the Alternate RACT III Proposal that the SCR control option is technically infeasible. Particulate matter emitted from the incineration of the sewage sludge could plug the catalyst restricting air flow by channeling the air flow through the catalyst and decreasing the contact area between the exhaust gases and the surface of the catalyst material. SCR was eliminated as a potential control for NOx emissions from the sewage sludge incinerators.

The other control options (SNCR, FGR, Good Combustion Practices/Proper Incinerator Operation, and Low NOx Burners) were considered to still be technically feasible options by DEP. The reasoning for this consideration is the construction costs are not under consideration at the technical feasibility step of the top-down review of control options. If the control could be applied to a system, then the control should be further evaluated in the top-down review process. A technical deficiency letter was sent to DELCORA on October 9, 2025 (see Attachment 2 for more details).

Table 5 summarizes the information for control efficiencies and economic feasibility of each of the remaining technically feasible control options from the information obtained in DELCORA's response to the technical deficiency letter received on October 17, 2025 (see Attachment 3).

Table 5. Ranking of Technically Feasible Control Technologies with Economic Feasibility Assessment

Ranking	Control Technology	Control Efficiency	NOx Reduced (tons/year)	Economic Feasibility ($/ton NOx Reduced)
1	Low NOx Burner w/ FGR	24% - 53%[a]	SSI 1: 9.68 SSI 2: 13.58	SSI 1[c]: 36,245.53 SSI 2[d]: 25,856.69
2	FGR	20% - 40%[b]	SSI 1: 8.27 SSI 2: 12.17	SSI 1: 12,230.69 SSI 2: 8,315.79
3	SNCR	SSI 1: 23.2% SSI 2: 25.2%	SSI 1: 5.00 SSI 2: 8.00	SSI 1: 17,179.34 SSI 2: 11,854.20
4	Good Combustion Practices/Proper Incinerator Operation	0	0	0

[a] Cost estimate performed at 44.9% control efficiency.
[b] Cost estimate performed at 38% control efficiency.
[c] SSI 1: Sewage Sludge Incinerator 1
[d] SSI 2: Sewage Sludge Incinerator 2

From the economic feasibility data summarized in Table 5, the only add-on control technology that approaches economic feasibility for the sewage sludge incinerators is FGR, and the cost effectiveness in controlling NOx emissions are still above the threshold of $7,500.00/ton NOx reduced.

In the write up for the technical deficiency response, DELCORA claimed that the information from the Chavond-Barry memo for the capital costs of FGR were used in the calculation. Also, the cost effectiveness calculation was performed with a 38% control efficiency for NOx emissions. FGR has not been applied to a sewage sludge incinerator, so it was claimed in the Chavond-Barry memo that there was not enough data to support this level of control for this type of source. DEP concurs with this evaluation. Some of the hearths in the incinerator are devoted to drying the sludge prior to incineration. The effectiveness of FGR may require more engineering than what was presented in the Chavond-Barry memo to achieve a balance in the air flow needed to properly dry and incinerate the sewage sludge with the control efficiency for NOx that can be obtained by FGR. The efficiency may not be as high as indicated in the cost effectiveness calculation, and these factors may show that FGR is more economically infeasible than indicated in the response to the technical deficiency (Attachment 3).

In accordance with 25 Pa. Code § 129.114(e)(2), DEP determines that DELCORA's Alternate RACT III Proposal to use good combustion practices/proper incinerator operation for controlling NOx emissions from the sewage sludge incinerators is considered RACT and will be submitted to the U.S. EPA for revision of the State Implementation Plan (SIP) for compliance with the 2015 Ozone NAAQS.

The following conditions were highlighted in the Title V Operating Permit for DELCORA for inclusion for compliance with the Alternate RACT III Plan for DELCORA in accordance with 25 Pa. Code §§ 129.114 and 129.115 and submittal to the U.S. EPA for inclusion in the State Implementation Plan (SIP) for Pennsylvania.

- Section E, Group#1, Condition #001(a)(2) – 15 lbs NOx/hr (220 ppm, dry volume at 7% Oxygen
- Section E, Group#1, Condition #007 – Monitoring
  - Condition #007(a)(2) – continuous oxygen concentration from the stack.
  - Condition #007(a)(4) – Continuous monitoring of temperature in Hearths 1 – 8.
  - Condition #007(b) – the amount and type of fuel combusted on a daily basis/monthly basis.
  - Condition #007(c) – quantity of sewage sludge incinerated on a continuous basis.
- Section E, Group#1, Condition #014 – Recordkeeping
  - Condition #014(a)(1) – the amount and type of fuel combusted on a daily basis/monthly basis.
  - Condition #014(a)(2) – quantity of sewage sludge incinerated on a continuous basis.
  - Condition #014(a)(3) – Continuous monitoring of temperature in Hearths 1 – 8.
  - Condition #014(a)(4) – date(s), time, and reason for any cessation of sewage sludge to the incinerator, other than for routine maintenance or planned outages.
  - Condition #014(a)(5) – continuous oxygen concentration from the stack.
  - Condition #014(b)(1) – copy of manufacturer's specification for the installation, maintenance, and operation of the burners.
  - Condition #014(b)(2) – a record of the stack test protocols and reports that are required by this Operating Permit.
  - Condition #014(g) – a record of all instrumentation calibration checks and maintenance reports.
- Section E, Testing, Condition #002 – Stack Testing Requirement for NOx.

The permit also contains a RACT strengthening condition limiting each sewage sludge incinerator to less than 65.7 tons NOx per year on a 12-month rolling period (Section E, Group#1, Condition #001(b)(2)).

5. Recommendation

I recommend the issuance of this Significant Modification to DELCORA's Title V Operating Permit to incorporate the Alternate RACT III proposal of good combustion practices/proper incinerator operation as part of the RACT III Plan to comply with the 2015 Ozone NAAQS.

Attachment 1. Calculations and AIMS Emission Inventory Data

Boiler Emissions:

B-2 Boilers Source ID No. 031

Heat Input for Each Building 2 Boiler = 1.26 MMBTU/hr
Number of Boilers in Building 2 = 2
Emission Factor for Boilers (AP-42, Vol. 1, Chapter 1.4) assuming no controls = 100 lbs $NOx/10^6$ scf Natural Gas)
Emission Factor Rating = B
Higher Heating Value of Natural Gas = 1,020 BTU/scf Natural Gas

Potential NOx Emissions from a Single Boiler in Building 2 = (1.26 MMBTU/hr)*(10^6 BTU/MMBTU)*(1 scf Natural Gas/1,020 BTU)*(100 lbs $NOx/10^6$ scf Natural Gas)*(8,760 hrs/yr)*(1 ton NOx/2,000 lbs NOx) = 0.54 tons NOx/year

B-3 Boilers Source ID No. 032

Heat Input for Each Building 3 Boiler = 1.50 MMBTU/hr
Number of Boilers in Building 3 = 3
Emission Factor for Boilers (AP-42, Vol. 1, Chapter 1.4) assuming no controls = 100 lbs $NOx/10^6$ scf Natural Gas)
Emission Factor Rating = B
Higher Heating Value of Natural Gas = 1,020 BTU/scf Natural Gas

Potential NOx Emissions from a Single Boiler in Building 3 = (1.50 MMBTU/hr)*(10^6 BTU/MMBTU)*(1 scf Natural Gas/1,020 BTU)*(100 lbs $NOx/10^6$ scf Natural Gas)*(8,760 hrs/yr)*(1 ton NOx/2,000 lbs NOx) = 0.64 tons NOx/year

Actual Emissions for Past Five (5) Years for Sewage Sludge Incinerator 1 (from AIMS Inventory)

Emission Year	**Reported NOx Emissions (tons/year)**
2020	18.010
2021	33.160
2022	26.470
2023	33.090
2024	20.462
Average	**26.238**

Actual Emissions for Past Five (5) Years for Sewage Sludge Incinerator 2 (from AIMS Inventory)

Emission Year	Reported NOx Emissions (tons/year)
2020	31.9300
2021	35.4200
2022	32.5600
2023	34.1200
2024	31.7292
Average	**33.1458**

Actual Emissions for Past Five (5) Years for B-2 and B-3 Boilers Combined (from AIMS Inventory)

Emission Year	Reported NOx Emissions (tons/year)
2020	0.3668
2021	0.3200
2022	0.4059
2023	0.4800
2024	0.7879
Average	**0.4721**

Attachment 2. Technical Deficiency Letter sent to DELCORA on October 9, 2025

October 9, 2025

VIA EMAIL: disantism@delcora.org, fitzgeraldi@delcora.org

Michael J. DiSantis
Director of Operations and Maintenance
Delaware County Regional Water Quality Control Authority (DELCORA)
100 East Fifth Street
Chester, PA 19016

Re: Significant Operating Permit Modification Application 23-00038
Technical Deficiency Letter
DELCORA
City of Chester, Delaware County
Authorization ID 1517799
Primary Facility ID Number 482687

Dear Michael DiSantis,

The Department of Environmental Protection (DEP) is in the process of reviewing your Reasonably Achievable Control Technology (RACT III) Proposal submitted through a Significant Operating Permit Modification application (application). DEP has identified the following technical deficiencies.

In accordance with 25 Pa. Code §§ 127.465 and 129.114(l), DEP requests the following additional information in support of the application:

1. Section 3.3.1 - Please provide documents, including the specific citations, that were the basis for eliminating NOx control technologies listed in Table 3-2.

2. Section 3.3.3.2 Selective Non Catalytic Reduction (SNCR) – In Section 3.3.3.1 of the application it was stated that SCR could not be installed prior to PM control equipment because it would lead to significantly greater construction costs. Cost obviously is not a factor in whether a control is technically feasible, but for the case of SCR, DEP agrees that it would be technically infeasible, for many reasons, including the temperature profile of the incinerator effluent exhaust. However, in Section 3.3.3.2 of the application, it is stated that the incinerator effluent exhaust is within the optimum operating temperature for SNCR; however, the PM control equipment greatly reduces the temperature. In similar fashion to the SCR analysis, SCNR could be evaluated before the PM control equipment and based on that temperature being within the optimum operating range, is technically feasible. There are many applications of SNCR including, but not limited to, industrial boilers, electric utility steam generators, thermal incinerators, cement kilns, pulp and paper power boilers, steel industry process units, refinery process units, and municipal solid waste energy recovery facilities. Many of these applications have to contend with high PM

loading in the exhaust. DEP does not agree that this is technically infeasible and a cost analysis in accordance with 25 Pa. Code § 129.114(i)(2)(i) is required.

3. Section 3.3.3.5 Low NOx Burners (LNB) - There are a few case studies presented in the publication "Existing Multiple Hearth Furnaces or New Solutions? Leveraging Your Existing (Paid For) Capital Assets" by Industrial Furnace Company Inc (IFCO).

   Several reasons are listed in your application as the basis for why LNB is deemed technically infeasible. The reasons listed in the application are as follows:

   a. Furnaces achieved reduction in NOx emission rates through use of LNB in tandem with additional control technologies
   b. Facilities in the study completed a full overhaul, which included installation of flue gas recirculation (FGR) before achieving lower NOx emission rates
   c. The 50-100% excess air required under normal operating conditions for the incinerators would be disrupted by installation of LNB
   d. EPA's RBLC database does not have any cases where LNB has been commercially available on SSIs in the U.S.

   The case study in the publication is on sludge treatment or incineration for existing multiple hearth furnaces. This study supports the technical feasibility of LNB.

   The study presents a case where multiple changes were performed. It does not eliminate LNB as an option. The case presents LNB/FGR as an option. LNB/FGR should be included in the top-down analysis. Additionally, many of the overhaul items are things that DELCORA has done or are evaluating if the changes are feasible. DELCORA has installed a multi-venturi scrubber. DELCORA, through RFD 10882, plan to evaluate using the top 2 hearths as an afterburner. The RBLC database captures permitting under non-attainment new source review (NA-NSR) or prevention of significant deterioration (PSD); therefore, in cases where those programs are not triggered, information is likely not posted in the RBLC database. Not finding anything in the RBLC database does not mean that LNB is not used (e,g., publication case study). Additionally, if DELCORA were required to pursue installation of LNB or LNB/FGR, it is unlikely that DELCORA would trigger NA-NSR or PSD due to the NOx PAL and current baseline emissions and expected reductions.

4. Section 3.3.3.3 of the narrative section of the application states that FGR is technical feasible and a cost analysis for FGR is presented in Section 3.3.5. DEP disregarded the statement in Section 3.3.3.5 that FGR was deemed infeasible.

   DEP does not agree that LNB or LNB/FGR are technically infeasible. A cost analysis, as defined in 25 Pa. Code § 129.114(i)(2)(i) is required.

5. Section 3.3.5 Step 4 – Evaluate Most Effective Controls and Document Results – The cost effectiveness ($/ton of NOx reduced) analysis in Table 3-3 of the application uses the project cost for the installation of both incinerators. Please evaluate each incinerator separately. Second, the cost effectiveness analysis, in accordance with 25 Pa. Code §

129.114(i)(2)(i), requires using methods in the "OAQPS Control Cost Manual". This requires that the total annual cost is estimated and used to calculate cost effectiveness. Please include the documentation of the FGR evaluation performed by Chavond-Barry Engineering Corp.

The above is requested in accordance with 25 Pa. Code §§ 127.465, 129.114(l), and the Policy for Implementing DEP Permit Review Process and Permit Decision Guarantee (PDG), and produced under the responsible charge of Mr. James Beach, P.E. In accordance with PDG, please submit the requested information no later than Friday, October 17, 2025. Should you have any questions regarding the identified deficiencies, please contact DEP to discuss your concerns or to schedule a meeting. The meeting must be scheduled before the Friday, October 17, 2025, deadline allotted for your reply, unless otherwise extended by DEP. You will have a final opportunity to correct any deficiencies, which will be summarized in a pre-denial letter, before DEP makes a final determination on your application.

If you believe the stated deficiencies are not significant, you have the option of asking DEP to make a decision based on the information you have already made available. If you choose this option, you should explain and justify how your current submission satisfies the deficiencies noted above. Please keep in mind that if you fail to respond on Friday, October 17, 2025, or before, your application may be denied.

Please upload the information through the Public Upload Page using the PIN assigned for the original submittal of the RACT III proposal. Please email Excel spreadsheets used in the cost effectiveness analysis to wgary@pa.gov.

If you have any questions concerning this matter, please contact me at 484.250.5062.

Sincerely,

Gary Walls
Air Quality Engineering Specialist
Air Quality Bureau

cc: Irene Fitzgerald, DELCORA
James A. Beach, P.E., Section Chief
Jillian Gallagher, Program Manager
Helen Morris, EGM
Regional Office

Attachment 3. Company Response to the Technical Deficiency Letter Sent on October 9, 2025

211 Welsh Pool Rd, Ste 238, Exton, PA 19341 / P 610.280.3902 / **trinityconsultants.com**

October 17, 2025

Gary Walls
Air Quality Engineering Specialist
PADEP – Southeast Regional Office
2 E Main Street
Norristown, PA 19401
[VIA PADEP ONBASE]

RE: Significant Operating Permit Modification Application 23-00038
Technical Deficiency Letter - DELCORA

Gary Walls:

On October 9, 2025, Delaware County Regional Water Quality Control Authority (DELCORA) received a technical deficiency notice for their Reasonable Available Control Technology (RACT III) proposal submitted through a significant operating permit modification application. A response is required to be submitted to Pennsylvania Department of Environmental Protection (PADEP) by October 17th, 2025. On October 10, 2025, DELCORA requested additional time for a documented response, this request was rejected. Please see the following responses to each item outlined in the October 9, 2025, technical deficiency letter (Letter). Supplemental calculations spreadsheets will also be emailed to Gary Walls at wgary@pa.gov.

Comment from PADEP Letter pertaining to Section 3.3.1 - Please provide documents, including the specific citations, that were the basis for eliminating NOx control technologies listed in Table 3-2.

Response: A memo from Chavond-Barry Engineering Corp. (CBE) dated March 11, 2022, is provided as part of this response, and is referenced herein in discussion of potential NO_X control technologies to waste incinerators.

Comment from PADEP Letter pertaining to Section 3.3.3.2 Selective Non Catalytic Reduction (SNCR) – In Section 3.3.3.1 of the application it was stated that SCR could not be installed prior to PM control equipment because it would lead to significantly greater construction costs. Cost obviously is not a factor in whether a control is technically feasible, but for the case of SCR, DEP agrees that it would be technically infeasible, for many reasons, including the temperature profile of the incinerator effluent exhaust. However, in Section 3.3.3.2 of the application, it is stated that the incinerator effluent exhaust is within the optimum operating temperature for SNCR; however, the PM control equipment greatly reduces the temperature. In similar fashion to the SCR analysis, SCNR could be evaluated before the PM control equipment and based on that temperature being within the optimum operating range, is technically feasible. There are many applications of SNCR including, but not limited to, industrial boilers, electric utility steam generators, thermal incinerators, cement kilns, pulp and paper power boilers, steel industry process units, refinery process units, and municipal solid waste energy recovery facilities. Many of these applications have to contend with high PM loading in the exhaust. DEP does not agree that this is technically infeasible and a cost analysis in accordance with 25 Pa. Code § 129.114(i)(2)(i) is required.

Response: As stated in the CBE memo in Attachment 1, there is no ideal location for ammonia injection under the current incinerator design. EPA Chapter 1, Selective Noncatalytic Reduction states:

> *" Sources with stable temperatures of 1550°F to 1950°F, uncontrolled NOx emissions above 200 ppm, and residence times of 1 second are generally well suited to SNCR and attain the highest levels of NOx control."*

Optimal location for ammonia injection is within the combustion stages of the incinerator, where optimal temperature can be maintained while minimizing the need for reheating. The current incinerator configuration does not achieve the target NOx concentrations. Stack testing data from 2022, 2023, and 2025 (refer to Attachment 2) show that the exhaust gas from SSI Units #1 and #2 consistently average below 160 ppm NOx. This relatively dilute exhaust stream concentration slows the reaction kinetics thus limiting potential NOx reduction and increasing ammonia slip.

DELCORA agrees that the technical challenges to implementing an SNCR system at the facility would have a negative impact of such a system's efficiency. DELCORA has included a cost analysis utilizing the published EPA Air Pollution Control Cost Estimation Spreadsheet. Note that the cost is presented in 2016 U.S. dollars and was adjusted for inflation using the Consumer Price Index (CPI). The EPA included an inflation adjustment using the Chemical Engineering Plant Cost Index (CEPCI) this was not utilized since this is a privately published index. DELCORA conservatively assumes the high end of the SNCR control efficiency range published in EPA Chapter 1, Selective Noncatalytic Reduction for Vapor, Sludge and Hazardous Waste Incinerators (91% reduction), and the total cost effectiveness for installing an SNCR on each SSI is as follows:

- SSI #1: $17,179.34 per ton NOx removed
- SSI #2: $11,854 per ton NOx removed

With conservatism built into the NO_X removal calculations, the cost of installing an SNCR on each SSI is higher than $7,500 per ton of NO_X removed and is above the cost considered reasonable in accordance with 25 Pa. Code 129.114(i)(1)(i). Based on economic infeasibility, SNCR is not considered further in the case-by-case RACT assessment for the facility.

Comment from PADEP Letter pertaining to Section 3.3.3.5 Low NOx Burners (LNB) - There are a few case studies presented in the publication "Existing Multiple Hearth Furnaces or New Solutions? Leveraging Your Existing (Paid For) Capital Assets" by Industrial Furnace Company Inc (IFCO).

Response: In the initial RACT III submission, the case studies in the publication were not considered as a technically feasible solution for reducing NO_X emissions from DELCORA SSIs with the installation of LNB because the subject facilities in the study completed large-scale equipment overhauls of their incinerators to optimize the implementation of LNB prior to achieving lower NO_X emissions rates. For the facility's incinerators, this would require the addition of flue gas recirculation systems (FGR), converting hearths #1 and #2 to afterburners, installing induced draft fan, updating controls systems to integrate the new technology, and redesigning the structure of the incinerator. In the original submittal, DELCORA asserted that such an undertaking is outside of what is considered reasonable in assessing what is technically feasible.

RFD 10882 is referenced as a possible transition of hearth #1 and #2 on SSI #1 to "zero hearths", this was not intended to act as a permanent afterburner transition. This RFD was completed to determine if low volatility VOCs are being released in the RTO and oxidize into HCl. This was not intended to be a permanent change unless HCl emissions from the final stack were decreased and should not be considered when evaluating DELCORA NOx RACT III.

Emissions reductions for this overhaul were taken from AP-42 with the use of low NOx Burners, and from the CBE memo titled "FLUE GAS RECIRCULATION IN MULTIPLE HEARTH BIOSOLIDS INCINERATORS". An FGR control efficiency of 38% was calculated and this is consistent with the memo received by CBE included in Attachment 1.

A cost analysis was drafted using the IFCO publication as a basis for the updating cost. This publication states "For a furnace that has none of the improvements above, the cost to go "from-zero-to-compliance" should be in the range of $4 to 6 million." $4 Million was chosen as the basis of this estimate since DELCORA already operates a wet scrubber for the control of sulfur dioxide and hydrogen chloride. This cost was not adjusted for inflation to present conservative cost effectiveness. The total cost for the LNB/FBR system installation is as follows:

- SSI #1: $39,749.37 per ton NOx removed
- SSI #2: $28,356.24 per ton NOx removed

The cost of overhauling the facility to accommodate installation of LNB and implementing a combination LNB/FGR control strategy on each SSI is higher than $7,500 per ton of NOx removed and therefore is above the cost considered reasonable in accordance with 25 Pa. Code 129.114(i)(1)(i). DELCORA has already included what is considered to be top-of-the-line burner technology for the sewage sludge incineration industry. In each SSI DELCORA has installed FIVES, model No. 4419 burners, which is suggested by the manufacturer to reduce NOx emissions. DELCORA maintains the assertion that traditional LNBs could not operate as a stand alone RACT for the sewage sludge incineration industry. Technical documentation of the burners currently installed in DELCORAs SSIs is included in Attachment 3.

Comment from PADEP Letter pertaining to Section 3.3.3.3 of the narrative section of the application states that FGR is technical feasible and a cost analysis for FGR is presented in Section 3.3.5. DEP disregarded the statement in Section 3.3.3.5 that FGR was deemed infeasible.

Response: Please see this comment addressed in the response to comment from PADEP Letter pertaining to Section 3.3.3.5 above.

Comment from PADEP Letter pertaining to Section 3.3.5 Step 4 – Evaluate Most Effective Controls and Document Results – The cost effectiveness ($/ton of NOx reduced) analysis in Table 3-3 of the application uses the project cost for the installation of both incinerators. Please evaluate each incinerator separately. Second, the cost effectiveness analysis, in accordance with 25 Pa. Code §129.114(i)(2)(i), requires using methods in the "OAQPS Control Cost Manual". This requires that the total annual cost is estimated and used to calculate cost effectiveness. Please include the documentation of the FGR evaluation performed by Chavond-Barry Engineering Corp.

Response: Calculations for the FGR system have been included in Attachment 4. The premise for these calculations was OAQPS Control Cost Manual. There is not an EPA control cost worksheet specific to the installation of an FGR system, costs were calculated following guidance from the OAQPS Control Cost Manual. The CBE memo estimated cost from 2022 (shown in Attachment 1) was adjusted for inflation and divided by 2 to represent changes to each SSI. Note, the $1.3 M estimate should be taken as an extremely conservative cost assessment for the installation of FGR control technologies. An engineering study was not conducted due to the time constraints of this response and would certainly add additional cost to this project. Retrofitting these incinerators with an FGR would require space and duct work at the facility and it is not known if this is possible with the current facility structure.

Additionally, it should be noted that CBE, the publisher of "FLUE GAS RECIRCULATION IN MULTIPLE HEARTH BIOSOLIDS INCINERATORS" states in the memo addressed to DELCORA (included in Attachment 1) that "On facilities this technology has been utilized, it was primarily implemented to reduce slagging within the incinerator, as such, we have limited data on the effectiveness of NOx reduction." Control efficiency was estimated to be 38% and results in the following cost assessments:

- SSI #1: $12,230.69 per ton NOx removed
- SSI #2: $8,315.79 per ton NOx removed

Therefore, the cost of installing an FGR system on each SSI is higher than $7,500 per ton of NOx removed, which is higher than the cost considered reasonable in accordance with 25 Pa. Code 129.114(i)(1)(i).

DELCORA maintains good combustion practices and proper incinerator operation for SSIs #001 and #002, and a NO_x emissions limit of 65.7 tons per year (TPY) (15 lb/hour per incinerator) is established as RACT in Title V Operating Permit (TVOP) No. 23-00038. Additionally, DELCORA operates under a Plant-wide Applicability Limit (PAL) of 82.56 TPY for NO_x. By adhering to current combustion and SSI operation practices, DELCORA will continue to comply with the emissions limitations specified in their TVOP and the PAL, ensuring adherence to RACT requirements.

DELCORA appreciates the Department's review of this response. Should you have any questions regarding the information presented in this letter, please contact Anthony Long by phone at (267) 275-5403, or at Anthony.long@trinityconsultants.com.

Sincerely,

Anthony Long
Consultant

Cc:
Irene Fitzgerald, DELCORA
Michael DiSantis, DELCORA
Brent Shick, Trinity Consultants
Matthew Page, Trinity Consultants

Attachment 1 – CBE NOx Controls Memo

CBE CHAVOND-BARRY ENGINEERING CORP.

P.O. Box 205
Blawenburg, NJ 08504

609-466-4900
www.Chavond-Barry.com

TO: Charlie Hurst

FROM: John Yu

DATE: March 11, 2022

RE: NOx Control Options

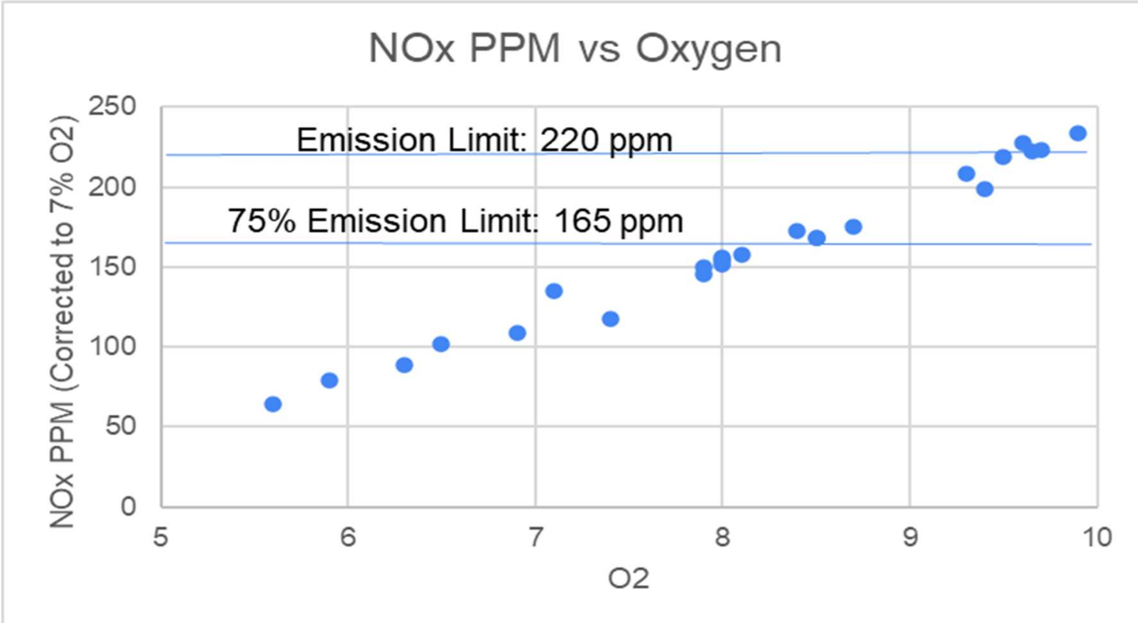
DELCORA is interested in NOx control options for the incineration system. Below is a summary of the various techniques and technologies available to control NOx emissions.

First of all, currently NOx emissions of DELCORA incinerators' NOx emissions are still under the emission limit, although there are some signs that the NOx emissions are trending upward. In the 2021 stack test, NOx emissions were at about 80% of the emission limit. So looking for NOx control options is a prudent forward-looking step, but at this time, it appears high level of removal efficiency is not needed and adequate control may be accomplished by changes to incinerator operations.

Following is an overview of various NOx control techniques and technologies.

1. **Operational adjustment (temperature)**: NOx is formed during the incineration process when nitrogen in the air or sludge reacts with oxygen in combustion air at high temperature. NOx formation is strongly correlated to combustion temperature and flame temperature. The formation of NOx is greater at higher temperature. Therefore, one way to control NOx is adjusting the combustion temperature in the incinerator and RTO. For example, it might be possible by increasing the size of the combustion zone of the furnace, the peak combustion temperature can be reduced while still providing clean burning. This can be accomplished by adjusting furnace conditions to split the hot combustion zone onto more hearths. RTO temperature can potentially be adjusted lower while still meeting the emission limit and site-specific operating limit.
   Disadvantages: Lower temperatures in the combustion zone could increase other pollutants, such as CO and hydrocarbons. Adjustment to operation needs to be slow and carefully monitored to find the optimal process setpoint, balancing out NOx generation and volatile destruction. Unfortunately, there is no added equipment to show concerned parties that DELCORA's facility has worked towards NOx reduction.

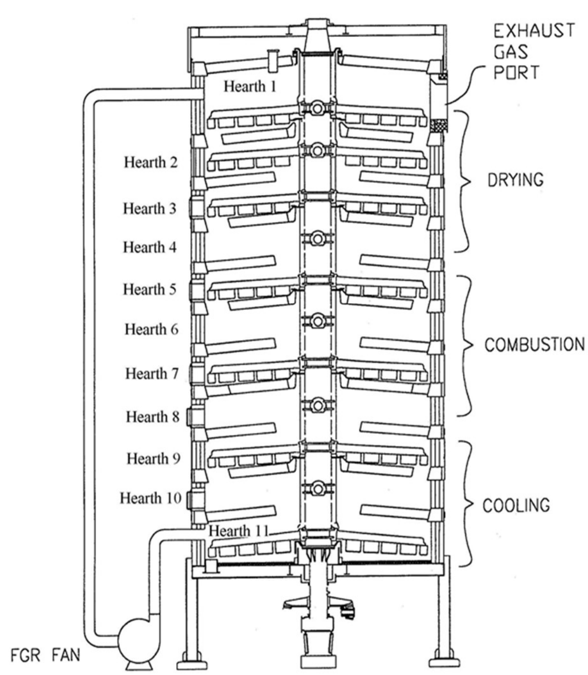
2. **Operational adjustment (oxygen):** As with above, limiting the amount of oxygen available during combustion would also limit the amount of NOx formation. This has been observed during the latest stack test, where the stack testing agency had a live NOx reading along with stack O2 reading. Below is the table of several points taken during second day of testing on Incinerator #2. It can be seen that O2 level has direct correlation with the NOx level, As such, controlling O2 level in the incinerator/RTO would help control the NOx level. Observation during Incinerator #1 testing shows similar trend, but at lower NOx emission level overall.



Disadvantages: As with controlling process temperature, while effective, this has no added equipment to show concerned parties that the facility has worked towards NOx reduction. Also this requires operators to pay close attention to an additional operation parameter.

3. **Flue gas recirculation (FGR)**: This technology was patented by Lou Barry of CBE and successfully installed in several facilities. This technique recycles some amount of flue gas from top hearth of the incinerator, where the flue gas is relatively cool and recirculates it down to below the combustion zone. This both reduces the combustion zone temperature and the oxygen content in the combustion zone, minimizing NOx formation. At the same time, the recirculated flue gas is going through the combustion zone twice, allowing for cleaner burning. This technology also has the added advantage of providing the operator with an additional control of the incinerator operation. By controlling the recirculation flow, the operator can control the incinerator's temperature profile and adjust where the sludge is burning within the incinerator. This technology would require a modification of the incinerator to place a FGR fan and duct work by the incinerator.

Figure 1 - Flue Gas Recirculation in a Multiple Hearth Furnace



Disadvantages: On facilities this technology has been utilized, it was primarily implemented to reduce slagging within the incinerator, as such, we have limited data on the effectiveness of NOx reduction. Few studies available suggest that FGR could reduce the NOx emission by about 20% to 40%. Total project capital cost investment for design and installation to both incinerators is estimated to be about $1.3 million dollars (budget estimate based on scaled up of a project from 10 years ago). Installation of FGR would need space by the incinerator to install the relatively large hot gas recirculation duct. As the FGR would be considered as a NOx control device, a site-specific parameter would likely be added on the operation of the FGR fan.

4. **Low NOx Burners**: Some burners are specially designed to minimize NOx formation, with special nozzle design to control the combustion to be in a lean air environment and minimize the peak flame temperature. By using low NOx burners, the amount of NOx formation from the burner flame will be reduced.
   Disadvantages: Switching out the burners would be a moderately high capital cost. Low NOx burners typically have a wider flame, which might not be appropriate for the incinerator or RTO. Given that NOx emissions have been low in some previous testing, the burners might not be a major contributor of NOx; therefore, using low NOx burners might have minimal effect in reducing NOx emission. This can be tested by operating the incinerator and RTO with no sludge and burners only to check the “baseline” NOx emission contributed by burners.

5. **SNCR (Selective Non-Catalytic Reduction):** This technique injects ammonia or urea into the flue gas, which converts NOx to N2 per following reaction: $4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$. This reaction requires residence time at temperature range of 1400°F to 2000°F. Optimal reaction temperature is around 1800°F.
   Disadvantages: Given the temperature requirement, there is no ideal location within the current process where ammonia injection can be made. If a dedicated vessel and burner are added for this process, it will be a considerable capital and operational expenditure. Implementing SNCR would also require storage of ammonia or urea on site. A concern with SNCR is that too much chemical dosing could cause ammonia slip, where extra unreacted ammonia is discharged in the flue gas. Therefore, ammonia testing and/or monitoring is typically required.

6. **SCR (Selective Catalytic Reduction):** Similar to SNCR, except a catalytic media is used to promote the reaction; therefore, the reaction temperature is reduced to as low as 400°F. Some special catalyst can reduce the reaction temperature to as low as 300°F, but their efficiency is low.
   Disadvantages: With the reduced temperature requirement, one possible location for the SCR vessel would be after the RTO. However, current RTO outlet temperature is around 200°F, so rising the RTO outlet temperature to 400°F for SCR would require additional fuel consumption during normal operation. The RTO outlet is designed for maximum of 450°F, so the temperature window for the RTO outlet will be relatively narrow (between 400°F and 450°F). The budgetary equipment pricing of a “polishing unit” design for NOx reduction of about 50% is around $1.6 million dollars. So, the

total project cost with engineering, installation, civil work, start-up/commissioning, etc. would likely to be near $2.5 million dollars. Higher removal efficiency to greater than 90% is available. Implementing SCR will also include needing to find space for the ammonia/urea storage tank and the SCR vessel. As with SNCR, additional ammonia testing and/or monitoring would likely be required.

There are some other technique and technologies for NOx control, such as using pure oxygen for combustion, using adsorbent/absorbent, etc. However, the cost and other requirements needed to implement those technologies makes them not practical for DELCORA. CBE recommends the initial step for NOx control would be to adjust the operating parameters. Based on the latest stack test observation, that has significant effect on NOx emission. If some sort of control device is desired, FGR could provide some level of reduction along with the benefit of providing the operator with additional incinerator control and reduction of slag formation. The temperature requirement for SNCR makes it impractical to implement at DELCORA's facility. SCR is a potential technology for NOx reduction to be utilized by the current system, but it requires installing and maintaining additional equipment and have extra chemical at the facility.

Please let us know if we can assist you further in this subject.

Attachment 2 – DELCORA Stack Testing Results

DELCORA Stack Test Results

MHF1

Pollutant	Units	Emissions Limit	Jan 25-26, 2022 Actual Emissions	Jan 25-26, 2022 % of Limit	Feb 21-23, 2023 Actual Emissions	Feb 21-23, 2023 % of Limit	Jun 27-28 & Jul 19, 2023 Actual Emissions	Jun 27-28 & Jul 19, 2023 % of Limit	July 9th, 2024 Actual Emissions	July 9th, 2024 % of Limit
CO	ppmvd @ 7%O2	3800	77.9	2.1%	56	1.5%			35.62	0.9%
NOx	ppmvd @ 7%O2	220	117.4	53.4%	150.3	68.3%			66.48	30.2%
SO2	ppmvd @ 7%O2	26	1.2	4.6%	1.2	4.6%	3.55	13.7%	0.98	3.8%
HCl	ppmvd @ 7%O2	1.2	0.69	57.5%	0.76	63.3%	0.97	80.8%	0.524	43.7%
PM	mg/dscm @ 7%O2	80	0.6	0.8%	0.8	1.0%			1.11	1.4%
PCDD/PCDF, TEQ	ng/dscm @ 7%O2	0.32	1.00E-03	0.3%	6.00E-04	0.2%				
PCDD/PCDF, TMB	ng/dscm @ 7%O2	5	1.30E-02	0.3%	1.90E-02	0.4%				
Cd	mg/dscm @ 7%O2	0.095	1.50E-04	0.2%	1.80E-04	0.2%				
Pb	mg/dscm @ 7%O2	0.300	5.50E-04	0.2%	1.20E-03	0.4%				
Hg	mg/dscm @ 7%O2	0.280	0.018	6.4%	2.30E-02	8.2%				
Fugitive emissions	%	5	0	0.0%	0	0.0%				

*Feb 2023 testing did not meet PADEP collection efficiency requirement for HCl so re-test was conducted in June 2023.

MHF2

Pollutant	Units	Emissions Limit	Jan 18-21, 2022 Actual Emissions	Jan 18-21, 2022 % of Limit	Feb 14-16, 2023 Actual Emissions	Feb 14-16, 2023 % of Limit	July 6-7, 2023 Actual Emissions	July 6-7, 2023 % of Limit	July 10-11, 2024 Actual Emissions	July 10-11, 2024 % of Limit
CO	ppmvd @ 7%O2	3800	59.8	1.6%	97.5	2.6%			49.06	1.3%
NOx	ppmvd @ 7%O2	220	157.8	71.7%	163.4	74.3%			131	59.5%
SO2	ppmvd @ 7%O2	26	1.2	4.6%	1.8	6.9%	4.13	15.9%	1.86	7.2%
HCl	ppmvd @ 7%O2	1.2	0.56	46.7%	2.0	**166.7%**	0.73	60.8%	0.331	27.6%
PM	mg/dscm @ 7%O2	80	6.9	8.6%	2.7	3.4%			0.948	1.2%
PCDD/PCDF, TEQ	ng/dscm @ 7%O2	0.32	1.50E-03	0.5%	1.30E-03	0.4%				
PCDD/PCDF, TMB	ng/dscm @ 7%O2	5	1.50E-02	0.3%	8.10E-02	1.6%				
Cd	mg/dscm @ 7%O2	0.095	2.70E-04	0.3%	2.10E-04	0.2%				
Pb	mg/dscm @ 7%O2	0.300	5.90E-03	2.0%	3.60E-03	1.2%				
Hg	mg/dscm @ 7%O2	0.280	2.30E-02	8.2%	2.70E-02	9.6%				
Fugitive emissions	%	5	0.4	8.0%	0	0.0%				

*Feb 2023 testing for HCl exceeded emission limit so re-test was conducted in July 2023.

Table 2-1: Summary of MHF-1 Emissions Results – PM, HCl, Gases & VE

Run Number	Run 1	Run 2	Run 3	Average
Date	6/24/25	6/24/25	6/24/25	
Stack Gas Parameters				
Oxygen Concentration, %	6.50	5.90	5.93	6.11
Carbon Dioxide Concentration, %	11.3	11.9	11.9	11.7
Volumetric Flow Rate, dscfm	9,656	9,708	9,768	9,711
Particulate Matter Data				
Concentration, grain/dscf	8.19E-04	1.49E-03	7.48E-04	1.02E-03
Concentration, grain/dscf @ 12% CO_2	8.68E-04	1.50E-03	7.56E-04	1.04E-03
Concentration, mg/dscm @ 7% O_2	1.81	3.15	1.59	2.18
Emission Rate, lb/hr	0.0678	0.124	0.0627	0.0847
Emission Factor, lb/ton of dry sludge	0.0337	0.0595	0.0312	0.0415
Hydrogen Chloride Data				
Concentration, ppmvd	0.0760	0.116	0.108	0.100
Concentration, ppmvd @ 7% O_2	0.0733	0.108	0.100	0.0938
Emission Rate, lb/hr	4.17E-03	6.42E-03	5.99E-03	5.52E-03
Carbon Monoxide Data				
Concentration, ppmvd	29.7	38.5	35.5	34.6
Concentration, ppmvd @ 7% O_2	28.7	35.7	32.9	32.5
Emission Rate, lb/hr	1.25	1.63	1.51	1.47
Nitrogen Oxide Data				
Concentration, ppmvd	121.2	90.1	93.3	101.5
Concentration, ppmvd @ 7% O_2	117.0	83.5	86.6	95.7
Emission Rate, lb/hr	8.39	6.27	6.53	7.06
Sulfur Dioxide Data				
Concentration, ppmvd	1.01	0.88	0.81	0.90
Concentration, ppmvd @ 7% O_2	0.97	0.82	0.75	0.85
Emission Rate, lb/hr	0.0973	0.0857	0.0787	0.0872
Total Hydrocarbons Data (as Propane)				
Concentration, ppmvd	0.84	0.90	0.74	0.83
Concentration, ppmvd @ 7% O_2	0.81	0.83	0.69	0.78
Emission Rate, lb/hr	0.0555	0.0601	0.0497	0.0551
Visible Emission Evaluation Data				
6-Minute Average Opacity, %	0.0	0.0	0.0	0.0

Table 2-2: Summary of Results – MHF-1 Method 26A Collection Efficiency

Sampling Location	Test Dates	Run #	Impingers 1-4 Catch Wt, ug	Impinger 5-6 Catch Wt, ug	Total Catch Wt, ug	Collection Efficiency, %
MHF 1	6/24/25	1	168.73	6.61	175.34	96.2%
	6/24/25	2	250.71	16.2	266.91	93.9%
	6/24/25	3	244.32	3.13	247.45	98.7%

Table 2-7: Summary of MHF-2 Emissions Results – PM, HCl, Gases & VE

Run Number	Run 1	Run 2	Run 3	Average
Date	7/1/25	7/1/25	7/1/25	
Stack Gas Parameters				
Oxygen Concentration, %	6.39	5.46	6.25	6.03
Carbon Dioxide Concentration, %	11.5	12.4	11.8	11.9
Volumetric Flow Rate, dscfm	9,439	9,395	9,318	9,384
Particulate Matter Data				
Concentration, grain/dscf	5.90E-04	4.17E-04	9.54E-04	6.54E-04
Concentration, grain/dscf @ 12% CO_2	6.17E-04	4.04E-04	9.68E-04	6.63E-04
Concentration, mg/dscm @ 7% O_2	1.29	0.860	2.07	1.41
Emission Rate, lb/hr	0.0477	0.0336	0.0762	0.0525
Emission Factor, lb/ton	0.0240	0.0181	0.0392	0.0271
Hydrogen Chloride Data *				
Concentration, ppmvd	0.332	0.309	0.134	0.258
Concentration, ppmvd @ 7% O_2	0.318	0.278	0.127	0.241
Emission Rate, lb/hr	0.0178	0.0165	0.00711	0.0138
Carbon Monoxide Data				
Concentration, ppmvd	52.1	69.2	40.4	53.9
Concentration, ppmvd @ 7% O_2	49.9	62.3	38.4	50.2
Emission Rate, lb/hr	2.15	2.84	1.64	2.21
Nitrogen Oxide Data				
Concentration, ppmvd	115.4	68.0	117.7	100.4
Concentration, ppmvd @ 7% O_2	110.6	61.2	111.7	94.5
Emission Rate, lb/hr	7.81	4.58	7.86	6.75
Sulfur Dioxide Data				
Concentration, ppmvd	1.63	1.12	1.07	1.28
Concentration, ppmvd @ 7% O_2	1.57	1.01	1.02	1.20
Emission Rate, lb/hr	0.154	0.105	0.100	0.120
Total Hydrocarbons Data (as Propane)				
Concentration, ppmvd	2.28	2.32	1.23	1.94
Concentration, ppmvd @ 7% O_2	2.19	2.09	1.16	1.81
Emission Rate, lb/hr	0.148	0.150	0.0785	0.125
Visible Emission Evaluation Data				
6-Minute Average Opacity, %	0.0	0.0	0.0	0.0

* HCl runs 2 and 3 had fractions below the detection limit (DL). Any non-detect sample fractions were included in the total result as the DL.

Table 2-8: Summary of Results – MHF-2 Method 26A Collection Efficiency

Sampling Location	Test Dates	Run #	Impingers 1-4 Catch Wt, ug	Impinger 5-6 Catch Wt, ug	Total Catch Wt, ug	Collection Efficiency, %
MHF 2	7/1/25	1	868.55	4.50	873.05	99.5%
	7/1/25	2	807.19	1.71	808.90	99.8%
	7/1/25	3	347.13	1.81	348.94	99.5%

* Runs 2 and 3 had fractions below the detection limit.

Attachment 3 - FIVES Model No. 4119 Technical Data Sheets

Combustion

North American Low Emissions
Quick Clean Burner

4419 Quick clean, low emissions gas burner

- Quick cleanout
- Direct spark ignition
- Dual fuel version available
- Multiple hearth furnaces
- Aluminum tower melters

Features | Quick Clean Burner

MULTIPLE HEARTH FURNACES

The 4419 Quick Clean burner was designed specifically to meet the requirements of multiple hearth furnaces. The Quick Clean burner enhances the circulation of furnace gases and eliminates or reduces many common problems found in sludge burning incinerators and carbon regeneration furnaces. It is well suited for modernization projects and new multiple hearth furnace installations.

ALUMINUM TOWER MELTER

The 4419 Quick Clean burner is ideal for the aluminum tower melter applications where material from the chamber can find its way into the burner tile. The ability to gain access into the burner tile without disconnecting the air and gas piping shortens the maintenance time required to get the furnace back into production. The medium velocity flame enhances heat transfer to the aluminum charge. The burner is designed for new or retrofit applications on melting furnaces.

RECESSED CONSTRUCTION

The burner body is recessed into the wall so that the flame initiation is 8" from the inside of the furnace chamber instead of the usual 18-24" typical for tangential firing. As a result, the furnace outer shell and the back of the burner operate at lower temperatures, reducing shell overheating problems and stress on UV detectors, ignition transformers and cables.

Because a mounting flange can be welded anywhere on the extension tube, the burner can be adapted to various wall constructions. The tile itself is formed in the field by the installer with a mandrel and becomes an integral part of the refractory wall. Various mounting flanges are available as options to fit individual applications.

MINIMIZED PLUGGING PROBLEMS

To minimize plugging problems, the burner refractory tile is tapered to a small discharge port which provides a medium velocity flame. There is no shelf or wide opening as with a conventional tile exit. The discharge velocity of the burner, combined with the small opening into the furnace, discourages the build up of material in front of or within the burner tile.

SUPERIOR STIRRING ACTION

The reduced port tile increases the velocity of the products of combustion exiting the tile. This causes a significant increase in turbulence and encourages entrainment of more furnace gases into the flame envelope. The mixing on the hearth increases while tempering the flame, which results in more uniform heat release without hot spots.

QUICK CLEANOUT and INSPECTION

If cleanout of the burner tile is required, the burner body design allows for quick and easy access to the burner internals. Disconnect the ignition cable and UV cell, and loosen the eight hex-head bolts that hold the backplate in place. Rotate the backplate a few degrees with the built-in handles and the burner internals can be pulled out, leaving a clear passage to the burner tunnel for easy maintenance and cleaning.

The main air and gas piping connections do not need to be disconnected to gain access to the burner tunnel. On the dual fuel version of the burner, the small oil and atomizing air lines must also be removed, so quick connect fittings are recommended.

DIRECT SPARK IGNITION

The 4419 incorporates direct spark ignition, eliminating the need for gas pilots, mixers and other premix pilot support parts. Maintenance of the burner is also reduced with fewer components to adjust and maintain. The ground wire and the igniter tips on the 4419 are easily replaced without special tools, and without requiring the purchase of a new igniter plug body.

LIGHTING ARRANGEMENTS

The burner air should be turned to low fire, and the spark turned on, before opening the burner gas valve. After the burner is lit, the spark must be turned off for proper burner operation. During the ignition period, a continuous 6000 volt (minimum) spark is required. Spark distributor systems cannot be used with 4419 Burners. When burning #2 oil, the burner should be lit with a small amount of gas first, which is turned off after the oil lights.

FLAME SUPERVISION

The North American 4419 has an internally purged flame supervision tube that runs from the backplate to the stabilizer. The sight line of the tube is angled to minimize the sensing of flame outside the tile by the U.V. flame detector. It is recommended that the UV connection be located at the 12 o'clock position for most installations. To optimize the flame signal during low fire oil applications, it may be necessary to have the UV tube sight line point to the "short side" of the angled wall as shown in Figure 1. The connection on the 4419 U.V. tube is a ½" male fitting. Refer to Bulletin 8832 for choices of U.V. flame detectors and adapters.

Features & Capacities | Quick Clean Burner

DUAL FUEL OPTION and OPERATION

The North American 6419 is the dual fuel version of the Quick Clean burner for firing #2 fuel oil or gas. The gas only 4419 Quick Clean burner can be easily converted to a 6419 in the field by adding an atomizer and an 1813 Sensitrol™ Oil Valve.

When operating with #2 oil, the atomizer should be operated with a constant 35"w.c. air pressure. During gas operation, use at least 4 osi atomizing air to cool atomizer (full atomizing air may be used); or for extended periods of operation on gas, the atomizer can be partially retracted or completely removed and stored: Use a blanking disk and gasket to seal the burner if the atomizer is removed (see page 7). Use the stop collar on the atomizer assembly to return the atomizer to the correct position when reinstalling the atomizer.

RATIO CONTROL and OPERATION

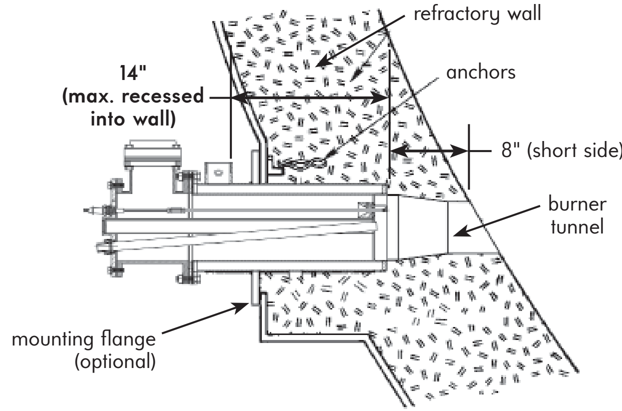
The 4419 burner fuel/air ratio can be controlled with a simple cross connected ratio regulator such as the North American 7216 for gas or the 7052 Ratiotrol for oil. Accurate fuel / air flows can be determined by using 8697 Metering Orifices in the fuel gas and air lines.

If furnace temperatures after shutdown rise above 1600°F, pass air through burner to prevent overheating.

CONSTRUCTION

The burner body, backplate and flanges are fabricated of steel, the extension tubes and flame stabilizer from stainless steel. The gas inlet coupling on the extension tube can be rotated independently of the air connection flange in 45° increments to aid in gas piping.

Mounting Diagram



Burner Size	Main Air Capacity (scfh) at various Air Pressures "w.c. 0.9	1.7	7.0	15.6	27.7	Natural Gas Pressure at 27.7"w.c., 10% XSA
4419-6-A	1,400	1,950	5,350	8,300	11,000	5.9"w.c.
4419-6-B	2,700	3,800	7,600	10,750	16,000	10.4"w.c.
4419-7-A	3,800	6,700	11,320	16,250	26,300	9.2"w.c.
4419-7-B	7,200	8,150	15,800	24,500	36,000	12.3"w.c.

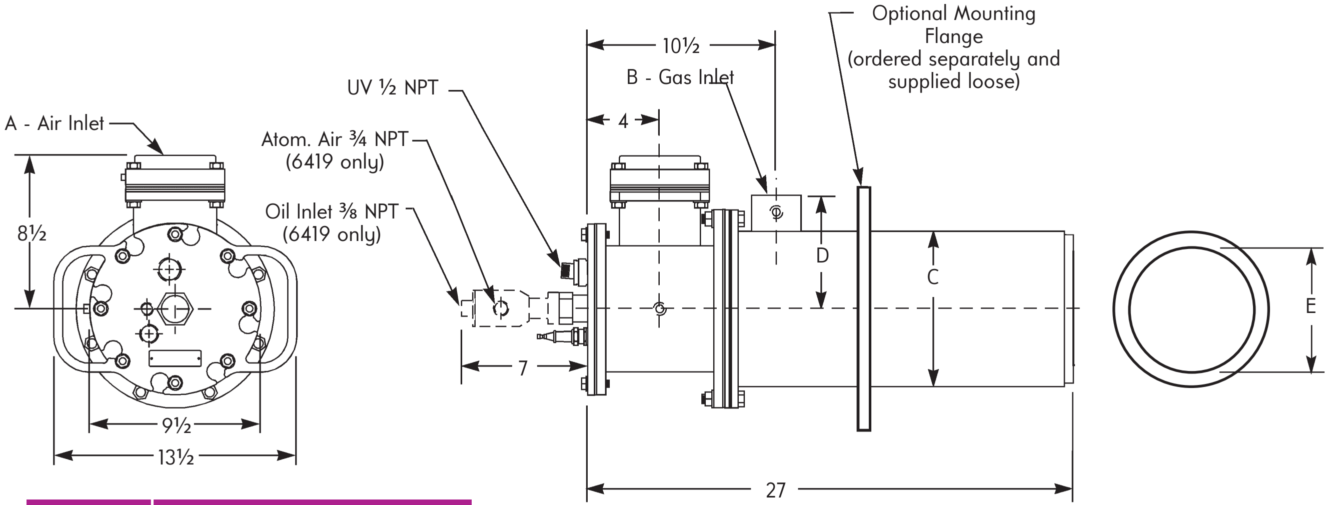
Burner Size	%Excess Air Limits for Gas and (#2 Oil)	%Excess Fuel Limits, Gas and (Oil) 27.7"w.c.	Flame Length Gas and (Oil) Feet 27.7"w.c. Air P. 10% XSA
4419-6-A	600 (100)	30 (30)	4 (4)
4419-6-B	400 (100)	20 (30)	4 (5)
4419-7-A	600 (100)	20 (30)	5 (6)
4419-7-B	800 (100)	15 (30)	6 (6)

Oil Atomizer Pressure/Flow Data

Oil Flow gal/hr	Oil Press. psi	Atom. Air at 35"w.c. scfh
28	5.9	255
26	5.4	280
24	4.8	285
22	4.3	320
20	3.9	345
18	3.3	360
16	2.9	370
14	2.4	385
12	2.1	395
10	1.8	410
8	1.5	420
6	1.3	435
5	1.1	435
4	1.0	445
3	0.9	450
2	0.8	460
1	0.65	470

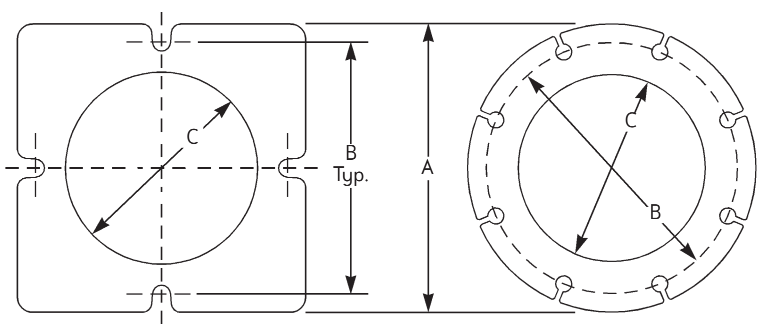
Dimensions | Quick Clean Burner

BURNER DIMENSIONS inches



4419/6419	A	B	C	D	E
-6-A, -6-B	3	1½	6⅝	5	5¾
-7-A, -7-B	4	2	8⅝	6 5/16	6 23/64

OPTIONAL MOUNTING FLANGES

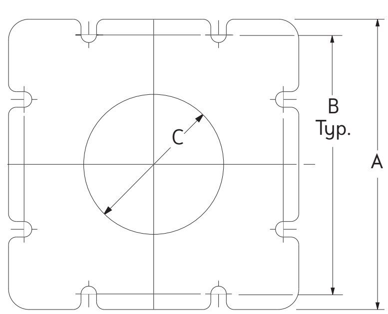


Square 4422 Style - Steel 1/2" thick
with 3/4" slots 4-32800-_

Round ANSI Style - Steel 1/2" thick
with 7/8" holes

		A	B	C
Square	4-32800-1	12	10½	6¾
	4-32800-2	12	10½	8¾
	4-32800-3	13½	12¼	6¾
	4-32800-4	13½	12¾	8¾

		A	B	C
Round	8767E-8	11	9½	6 11/16
	4-33071-1	13½	11¾	6 11/16
	8767E-9	13½	11¾	8¾

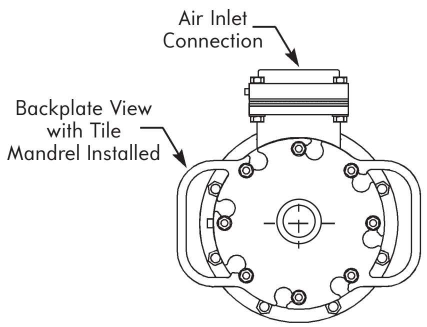


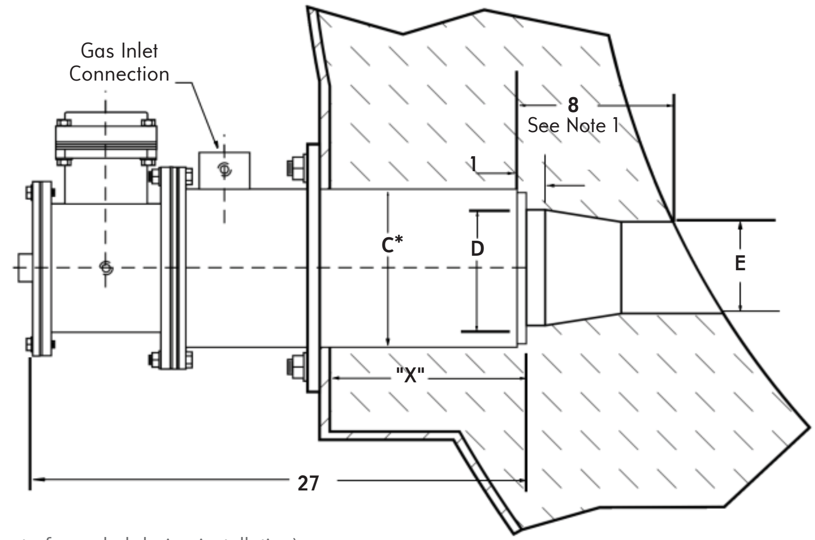
Square 6421 Style - Steel 1/2" thick
with 3/4" slots 4-40286-_

		A	B	C
Square	4-40286-1	14	12½	6¾
	4-40286-2	14	12½	8¾
	4-40286-3	16	14¾	6¾
	4-40286-4	16	14¾	8¾

DIMENSIONS SHOWN ARE SUBJECT TO CHANGE. PLEASE OBTAIN CERTIFIED PRINTS FROM FIVES NORTH AMERICAN COMBUSTION, INC. IF SPACE LIMITATIONS OR OTHER CONSIDERATIONS MAKE EXACT DIMENSION(S) CRITICAL.

REFRACTORY DIMENSIONS inches





4419/6419	C*	D	E
-6-A, -6-B	6⅝	4²³⁄₃₂	3½
-7-A, -7-B	8⅝	6⁵⁄₁₆	5

* **C** = diameter of outer burner tube (becomes part of mandrel during installation).

DIMENSIONS SHOWN ARE SUBJECT TO CHANGE. PLEASE OBTAIN CERTIFIED PRINTS FROM FIVES NORTH AMERICAN COMBUSTION, INC. IF SPACE LIMITATIONS OR OTHER CONSIDERATIONS MAKE EXACT DIMENSION(S) CRITICAL.

INSTRUCTIONS

1. It is important to maintain the 8" tile dimension as shown in illustration above.

2. Determine burner insertion dimension "X", taking into consideration actual wall thickness and making allowance for required 8" tile dimension.

3. Attach burner mounting studs to furnace casing and provide burner access hole in furnace casing using burner mounting flange as a template.

4. Secure burner mounting flange to outer burner tube as required to provide insertion dimension "X" determined above.

5. Insert burner into furnace casing access hole, engaging the mounting flange and studs as required to provide the desired location of gas inlet connection.

6. Position the air inlet connection as desired by removing the burner body hardware and rotating the burner body as required. Re-attach the burner body using the hardware just removed and the tube gasket shipped loose with the burner.

7. Loosen the eight flange-head hex bolts that secure the burner backplate to the body. Rotate the burner backplate counterclockwise until the bolt heads are aligned with the enlarged portion of the backplate mounting holes. Carefully withdraw the backplate assembly and store in a safe location.

8. Install mandrel assembly shown on page 2 and secure mandrel mounting plate to burner body by re-tigntening the eight flange-head hex bolts from step 7.

9. With the tile mandrel properly secured to and aligned with the burner, the burner tile can be formed by the application of a suitable refractory material (usually cast or rammed) around the tile mandrel.

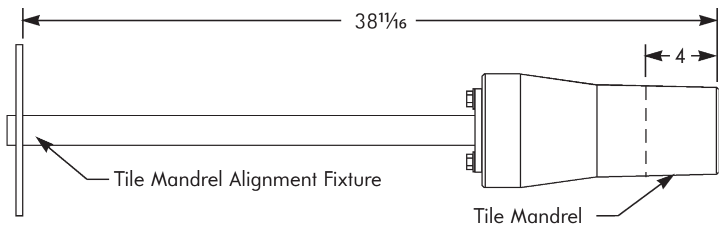
10. To provide a suitable transition between the burner and tile, the cast or rammed refractory should penetrate far enough into the opening around the burner to engage several inches of the outer burner tube, effectively untilizing the outer burner tube as part of the mandrel. (See dimension "C".)

11. Make sure that a suitable mold release agent (Penreco® Cream, Crete-Lease®, etc.) is applied to all wetted surfaces to assist in mandrel and burner removal once the refractory sets up.

12. When re-inserting the backplate assembly, rotate so the UV connection is at 12 o'clock unless otherwise required for low fire oil applications. (See "Flame Supervision" section on page 2.) The backplate gasket is shipped loose with the burner to be installed when re-inserting the backplate assembly.

OPTIONAL TILE MANDRELS FOR RAMMED AND POURED WALLS

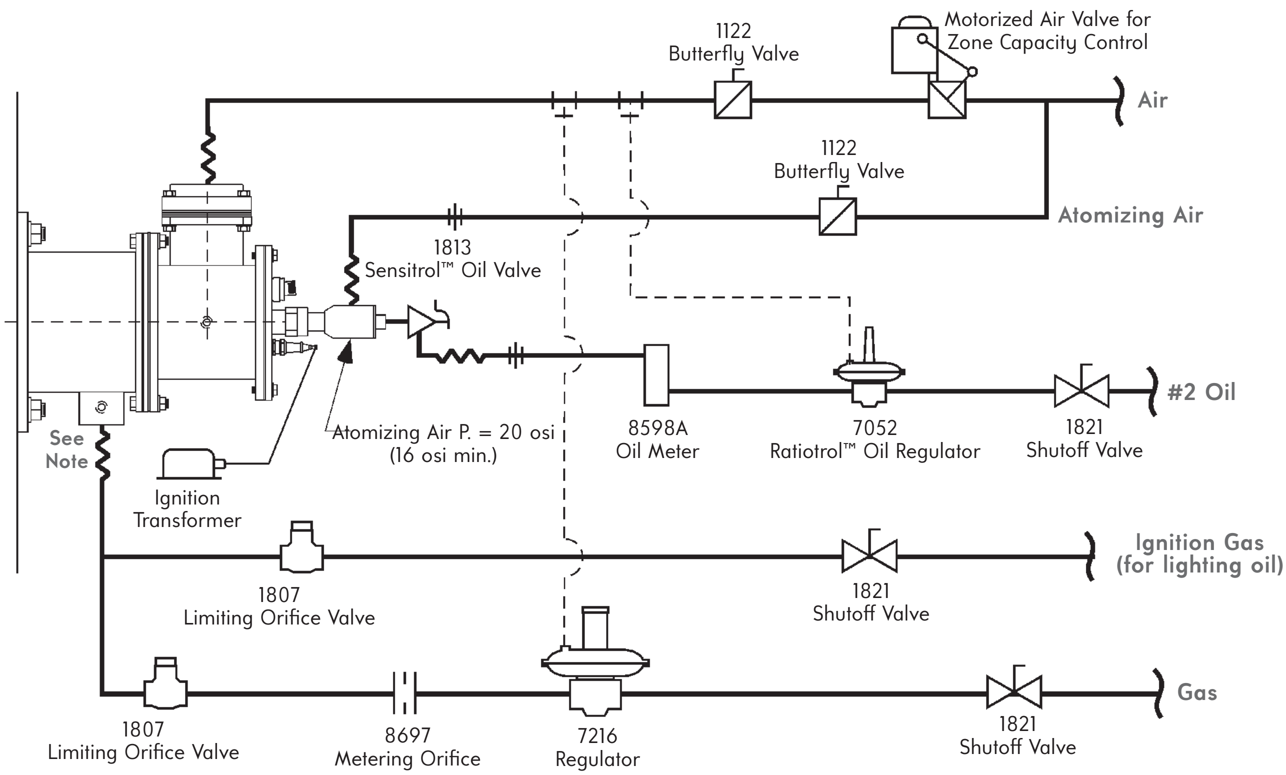
The 4419/6419 MHF burner requires a tile that is formed by ramming or pouring refractory around a mandrel in the furnace wall. North American can supply an alignment fixture with a nickel plated aluminum mandrel. The alignment fixture holds the mandrel in the correct location relative to the burner exit. The nose of the mandrel also has 4" of extra length to accommodate curved wall construction.



4419/6419	-6-A, -6-B	-7-A, -7-B
Tile Mandrel	4-33092-1	4-33093-1
Tile Mandrel Alignment Fixture	4-33094-1	
Tile Mandrel Assembly	4-32490-1	4-42129-1

TYPICAL RATIO CONTROL PIPING SCHEMATIC

Does not include gas train components. Atomizing air and oil lines are not used on the 4419 gas only version.



NOTE: Gas connection is shown at bottom for clarity. Whenever possible gas and air connections should not be located at the bottom of the burner on dual fuel applications.

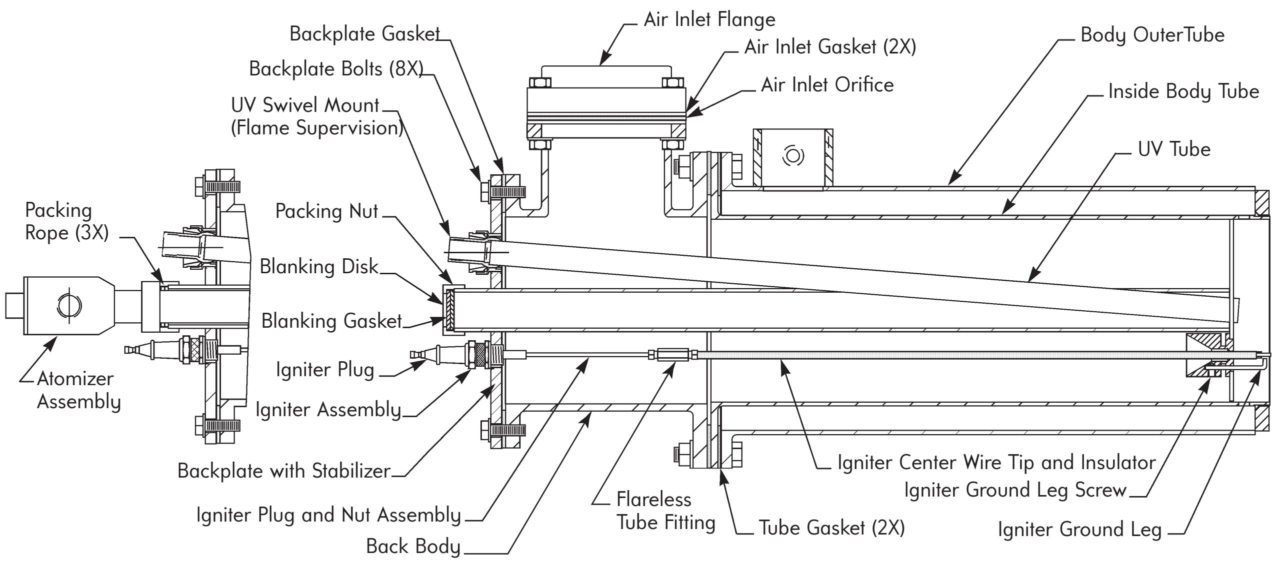
Ordering Information & Parts List | Quick Clean Burner

_ 419 - _ _

Fuel Selection
- **4** for Gas Only
- **6** for dual Fuel (Gas and #2 Oil)

Size Code	Air Inlet	Air capacity at 27.7"w.c.
-6-A	3"	11,000 scfh
-6-B	3"	16,000 scfh
-7-A	4"	26,300 scfh
-7-B	4"	36,000 scfh

Examples: 4419-6-A Gas Only 11,000 cfh Air at 27.7"w.c.
6419-7-A Dual Fuel 27,500 cfh Air at 27.7"w.c.



<table>
<tr><th rowspan="2">Part Name</th><th colspan="4">Burner designation</th></tr>
<tr><th>-6-A</th><th>-6-B</th><th>-7-A</th><th>-7-B</th></tr>
<tr><td>Air Inlet Flange</td><td>4-1695-4</td><td>4-1695-4</td><td>4-1695-5</td><td>4-1695-5</td></tr>
<tr><td>Air Inlet Gasket</td><td colspan="4">4-5371-3</td></tr>
<tr><td>Air Inlet Orifice</td><td>4-33089-1</td><td>4-33089-2</td><td>4-33089-3</td><td>4-33089-4</td></tr>
<tr><td>Back Body</td><td colspan="4">4-33088-1</td></tr>
<tr><td>Backplate with Stabilizer</td><td>4-33082-1</td><td>4-33082-1</td><td>4-33083-1</td><td>4-33083-1</td></tr>
<tr><td>Backplate Bolts</td><td colspan="4">R069-2500-C</td></tr>
<tr><td>Backplate Gasket</td><td colspan="4">4-33081-1</td></tr>
<tr><td>Blanking Disk (4419 only)</td><td colspan="4">4-33080-1</td></tr>
<tr><td>Blanking Disk Gasket (4419 only)</td><td colspan="4">4-33079-1</td></tr>
<tr><td>Body Outer Tube</td><td>4-41784-1</td><td>4-41784-1</td><td>4-41783-1</td><td>4-41783-1</td></tr>
<tr><td>Flareless Tube Fitting</td><td colspan="4">R916-7500-B</td></tr>
<tr><td>Igniter Assembly (complete)</td><td colspan="4">4-33009-1</td></tr>
<tr><td>Igniter Plug and Nut Assembly</td><td colspan="4">4-33009-3</td></tr>
<tr><td>Igniter Center Wire Tip and Insulator</td><td colspan="4">4-33009-2</td></tr>
<tr><td>Igniter Ground Leg</td><td colspan="4">4-33073-1</td></tr>
<tr><td>Igniter Ground Leg Screw</td><td colspan="4">R776-2030-B</td></tr>
<tr><td>Inside Body Tube</td><td>4-33075-1</td><td>4-33075-1</td><td>4-33074-1</td><td>4-33074-1</td></tr>
<tr><td>Observation Port</td><td colspan="4">8790-0</td></tr>
<tr><td>Oil Atomizer Assembly (6419 only)</td><td colspan="4">3-20358-1</td></tr>
<tr><td>Packing Nut</td><td colspan="4">4-33072-1</td></tr>
<tr><td>Packing Rope 3 × 3½" (6419 only)</td><td colspan="4">R540-0120</td></tr>
<tr><td>Sensitrol™ Oil Valve (6419 only)*</td><td>1813-02-A</td><td>1813-02-B</td><td>1813-02-C</td><td>1813-02-C</td></tr>
<tr><td>Tube Gasket</td><td colspan="4">OA3-2302-25F4</td></tr>
<tr><td>UV Swivel Mount Assembly</td><td colspan="4">4-32740-1</td></tr>
<tr><td>UV Tube</td><td>4-33090-1</td><td>4-33090-1</td><td>4-42642-1</td><td>4-42642-1</td></tr>
</table>

* Recommended 1813 Sensitrol Valve is not included as part of burner assembly and must be ordered separately.

fives

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www.fivesgroup.com

Introducing The FivesNA 4419/6419 Multihearth Furnace "MHF" Burner

The 4419/6419 MHF Advantage

Sturdy industrial construction

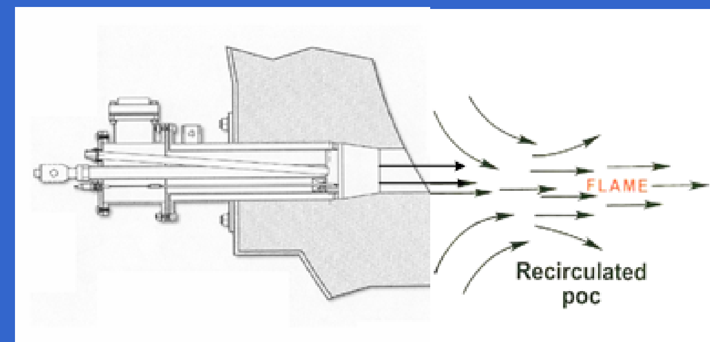
The 4419/6419 MHF Advantage

- Minimized plugging
- Quick cleanout when needed
- Recessed burner body
- Direct spark ignition
- Convertible to dual fuel
- Sturdy industrial construction
- Flexible air & gas piping options

The 4419/6419 MHF Advantage

Minimized plugging

- The discharge velocity of the burner combined with the small opening into the furnace discourages the build up of material in the burner tile

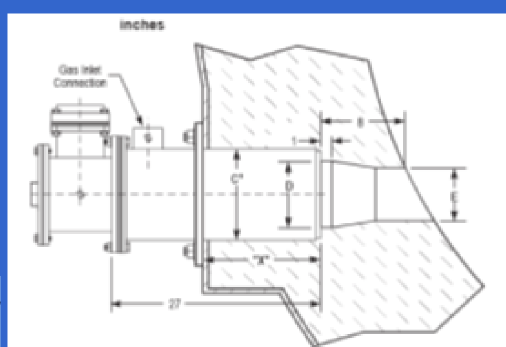


The 4419/6419 MHF Advantage

Recessed construction

- The tile is formed in the field by the installer with a mandrel and becomes an integral part of the refractory wall.

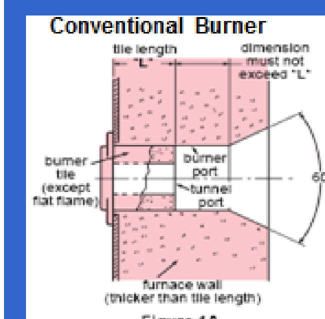
4419/6419	C*	D	E
-6-A, -6-B	6 5/8	4 23/32	3 1/2
-7-A, -7-B	8 5/8	6 5/16	5



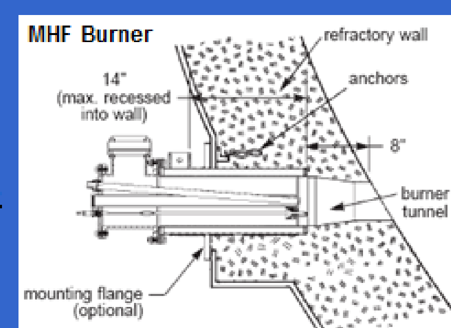
The 4419/6419 MHF Advantage

Recessed construction

- The burner body tube is recessed into the furnace wall so that the flame initiation is 8” from the inside of the furnace chamber.



VS

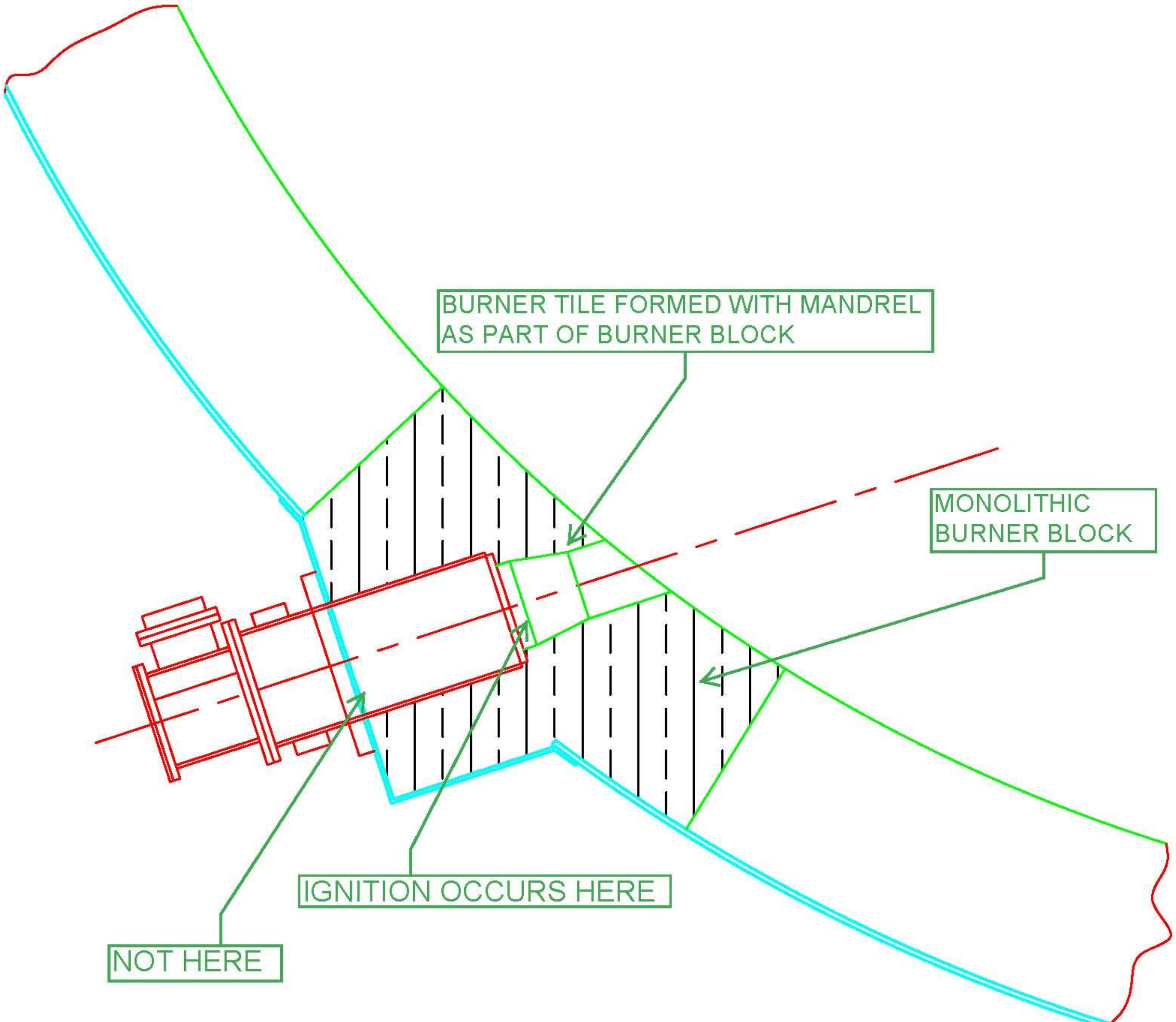


- **The MHF Burner is specifically designed for Multiple Hearth Furnaces. Its specific design and robust construction have proven to be extremely reliable in the field.**

- **Flame ignition is near the inner wall of the furnace.**
    - **Flyash does not contact the flame within the burner tunnel, so slagging up the burner port is eliminated.**
    - **Most, if not all, of the flame propagation occurs in the furnace atmosphere.**
    - **The 5 foot long fast moving flame entrains relatively cool gas from the furnace atmosphere, lowering the flame temperature.**
    - **Cooler flame = Lower NOx + lower slagging potential.**

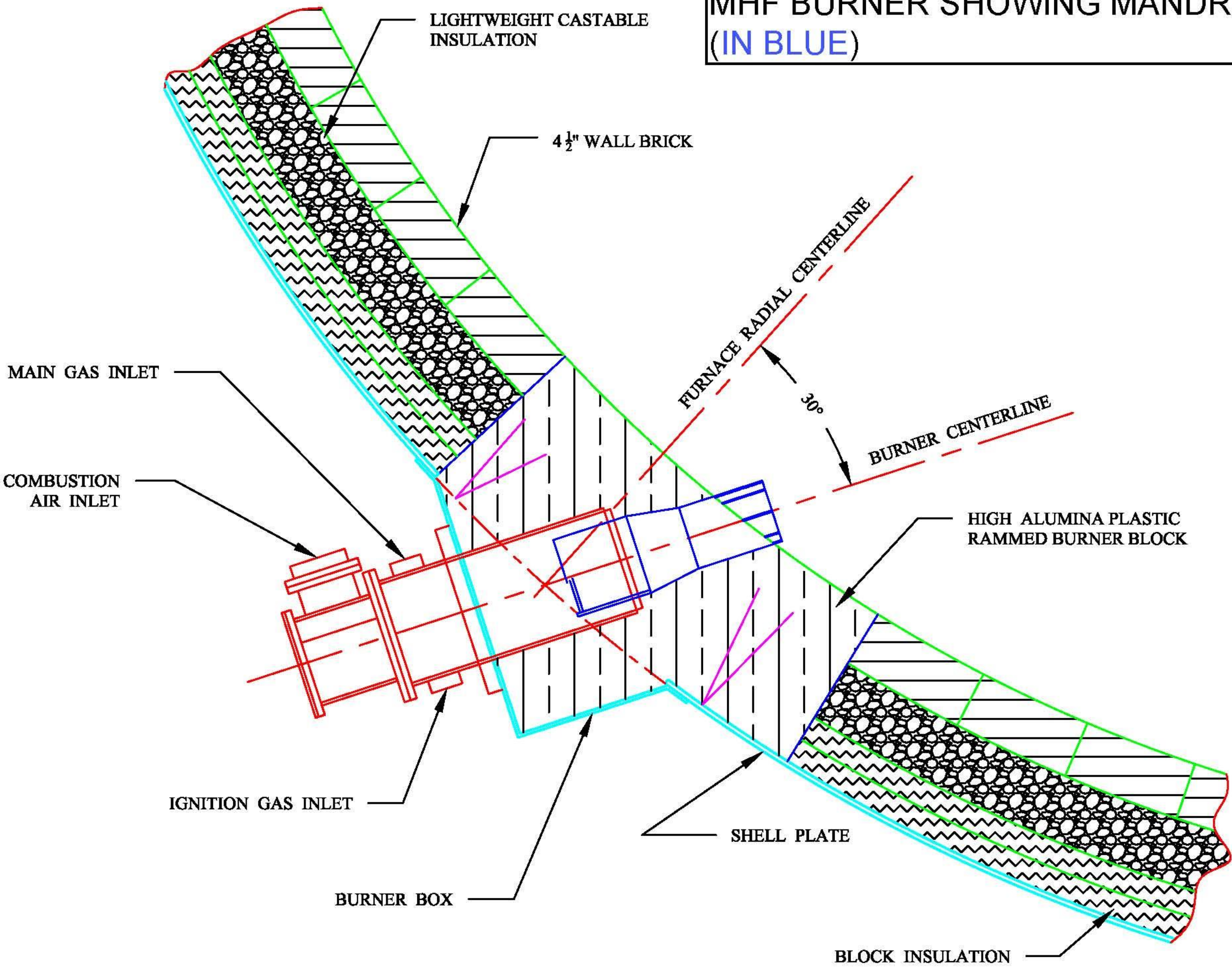
- **Burner tile is formed in the field.**
    - **The burner tile is part of a single monolithic refractory block.**
    - **Factory supplied tiles have exhibited a very high incidence of severe cracking in multiple hearth furnaces installations.**
    - **Cracks in burner tiles/blocks tend to provide a good path for flames to find their way back to the shell and produce cherry-red hot spots.**
    - **The monolithic block not only does not tend to crack, but it also has no seams, which can behave like cracks.**

- **The backing plate and burner internals can be removed for burner and port maintenance without touching the gas and air piping.**



"MHF" BURNER INSTALLATION

MHF BURNER SHOWING MANDREL
(IN BLUE)



Attachment 4 – Cost Estimation Calculations

DELCORA, Chester PA
Cost Analysis

Inflation Adjustment

Original Cost Estimate[1]:	$ 1,300,000.00
Cost Per SSI (Two Total):	$ 650,000.00
Consumer Price Index (March 2022):	287.504
Consumer Price Index (August 2025):	323.976
Cost in 2025, Per SSI:	$ 732,457.29

1. Cost based off Chavond-Barry Engineering Corp Estimate drafted in 2022, adjusted for inflation.

FGR NOx Reduction Calculation

	No FGR [lb/Dry Ton]	FGR [lb/Dry Ton]	Reduction
Hartford	3.6	1.71	53%
Woonsocket	7.63	5.78	24%

1. Date from "FLUE GAS RECIRCULATION IN MULTIPLE HEARTH BIOSOLIDS INCINERATORS" Published by CBE

Cost Analysis for a Flue Gas Recirculation System

SSI	Project Cost (USD)	Current NOx Emissions, Facility Total (tpy)	Control Efficency[1] [%]	NOx Emissions, with FGR (tpy)	Total NOx Reduction (tpy)
#1	$732,457.29	21.56	38%	13.28673853	**8.27**
#2	$732,457.29	31.71	38%	19.54185894	**12.17**

1. Average NOx Reduction taken from FGR NOx Reduction Calculation

Cost Analysis for a Flue Gas Recirculation System & Low NOx Burners

SSI	Project Cost[1]	Current NOx Emissions, Facility Total	2024 Natural Gas Usage	NOx Emissions Factor[2]	LNB Emissions Factor[2]	2024 NOx Emissions From NG Combustion	NOx Emissions From LNB NG Combustion	Estimated Emissions Using LNB[3]	FGR Control Efficency[4]	NOx Emissions, with FGR	Total NOx Reduction
	(USD)	(tpy)	[MMscf]	[lb/MMscf]	[lb/MMscf]	[tpy]	[tpy]	[tpy]	[%]	(tpy)	(tpy)
#1	$4,000,000.00	21.56	91.58	190.00	140.00	8.70	6.41	19.27	38%	11.87583642	**9.68**
#2	$4,000,000.00	31.71	91.32	190.00	140.00	8.68	6.39	29.43	38%	18.13488115	**13.58**

1. Total project cost for this installation is estimated to be $4 Million USD. This assessemnt comes from the "EXISTING MULTIPLE HEARTH FURNACES OR NEW SOLUTIONS? LEVERAGING YOUR EXISTING (PAID FOR) CAPITAL ASSETS" publication from AFCO. The lower end of the cost assessment was used due to a scrubber already being installed. The cost was not addjusted for inflation to provide an even more conservative assessment.
2. Factors Taken from AP-42 Section 1.4, Table 1.4-2
3.NOx emissions using LNB were estimated by adjusting 2024 actual emissions—subtracting natural gas combustion NOx and adding LNB-based combustion NOx
4. Average NOx Reduction taken from FGR NOx Reduction Calculation

Assumptions and Constant Variables			
$Cost_{elec}$	Electricity Cost	0.1461	$/kWh
i	Interest Rate	7.25	%
n	FGR Life Span	25	years
P	FGR Electricity Consumption	20	kW
t_{op}	Operating Hours	8760	hours

Total Cost Analysis

	Total Capital Investment [TCI]	Annual Maintenance Cost	Electricity Cost	Direct Annual Cost [DC]	Administrative Charges [AC]	Capital Recovery Factor [CRF]	Capital Recovery Cost [CR]	Indirect Annual Cost [IDAC]	Total Annual Cost	Total NOx Reduction (tpy)	Cost Per Ton NOx (USD)
FGR Only											
SSI #1	$732,457.29	$10,986.86	$ 25,596.72	$36,583.58	$329.61	0.08775190247	$64,274.52	$64,604.13	$101,187.71	8.27	**$12,230.69**
SSI #2	$732,457.29	$10,986.86	$ 25,596.72	$36,583.58	$329.61	0.08775190247	$64,274.52	$64,604.13	$101,187.71	12.17	**$8,315.79**
FGR & LNB											
SSI #1	$4,000,000.00	$ -	$ -	$ -	$ -	0.08775190247	$351,007.61	$351,007.61	$351,007.61	9.68	**$36,245.53**
SSI #2	$4,000,000.00	$ -	$ -	$ -	$ -	0.08775190247	$351,007.61	$351,007.61	$351,007.61	13.58	**$25,856.69**

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 15.67 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 91,577,175 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 SO_2 emission rate: Not Applicable

Ash content (%Ash): 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, %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	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	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})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.12	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.011101611	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation	250	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	365	days
Estimated equipment life	20	Years

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: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016			
CEPCI for 2016	541.7	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.25	Percent		
Fuel ($Cost_{fuel}$)	2.97	$/MMBtu		
Reagent ($Cost_{reag}$)	0.29	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.1461	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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 ente and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/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.	
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 *Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	16	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	132,884,027	scf/Year	
Actual Annual fuel consumption (Mactual) =		91,577,175	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.689	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	6037	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	91	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1.76	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	5.31	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)			Not applicable; factor applies on fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	#VALUE!		Not applicable; factor applies on fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor apply to plants located at elevat 500 feet.
Atmospheric pressure at 250 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* 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: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	3	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	0.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	3,100	gallons (storage needed to store a 365 day reage 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	0.0962

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	0.1	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	1	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.01	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\times10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cos to coal-fired boilers

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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 ($SNCR_{cost}$) =	\$177,520 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	\$282,244 in 2016 dollars
Total Capital Investment (TCI) =	\$597,692 in 2016 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 ($SNCR_{cost}$) =	\$177,520 in 2016 dollars

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 2016 dollars

#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}) =	\$282,244 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$9,804 in 2016 dollars
Indirect Annual Costs (IDAC) =	$57,767 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$67,571 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$8,965 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$612 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$103 in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$15 in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$109 in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2016 dollars
Direct Annual Cost =		$9,804 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$269 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$57,498 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$57,767 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$67,571 per year in 2016 dollars
NOx Removed =	5 tons/year
Cost Effectiveness =	$12,727 per ton of NOx removed in 2016 dollars

DELCORA, Chester PA
Emissions Summary

2024 Actual Emissions

Month	Incinerator #1 (Source ID 001) Sludge Processed (tons)	Incinerator #2 (Source ID 002) Sludge Processed (tons)	Total Sludge Processed (tons)	Incinerator #1 (Source ID 001) Natural Gas Usage (scf)	Incinerator #2 (Source ID 002) Natral Gas Usage (scf)	Incinerator #1 (Source ID 001) NOx Emissions (tons)	Incinerator #2 (Source ID 002) NOx Emissions (tons)	Incinerator #1 Emissions Rate (lb NOx/ton Sludge)	Incinerator #2 Emissions Rate (lb NOx/ton Sludge)	Incinerator #1 Emissions Rate (lb NOx/MMBtu)	Incinerator #2 Emissions Rate (lb NOx/MMBtu)
1/1/2024	853.80	652.80	1506.60	7797424.15	7212598.58	2.90	2.35	6.79	7.20	0.19	0.17
2/1/2024	629.50	933.50	1563.00	6915946.60	7761906.69	2.14	3.36	6.80	7.20	0.16	0.22
3/1/2024	713.70	1017.50	1731.20	6937540.29	7472652.19	2.43	3.66	6.81	7.19	0.18	0.25
4/1/2024	848.30	821.00	1669.30	8363288.47	5906905.19	2.88	2.96	6.79	7.21	0.18	0.26
5/1/2024	691.20	985.30	1676.50	8883490.09	7339197.35	2.35	3.55	6.80	7.21	0.14	0.25
6/1/2024	536.30	704.30	1240.60	5819370.00	6071450.00	1.82	2.54	6.79	7.21	0.16	0.22
7/1/2024	755.10	782.30	1537.40	8717874.64	8441500.00	1.52	2.32	4.03	5.93	0.09	0.14
8/1/2024	733.20	680.80	1414.00	6566046.00	5008939.94	1.10	1.92	3.00	5.64	0.09	0.20
9/1/2024	744.00	760.20	1504.20	6173371.27	8706967.23	1.12	2.15	3.01	5.66	0.09	0.13
10/1/2024	511.60	827.60	1339.20	6727444.76	8668119.87	0.83	2.34	3.24	5.65	0.06	0.14
11/1/2024	807.90	808.40	1616.30	8561479.88	9057045.49	1.21	2.28	3.00	5.64	0.07	0.13
12/1/2024	841.50	808.70	1650.20	10113899.02	9675177.66	1.26	2.28	2.99	5.64	0.06	0.12
Totals:	**8666.10**	**9782.40**	**18448.50**	**91577175.18**	**91322460.19**	**21.56**	**31.71**	**--**	**--**	**0.12**	**0.19**
							Average:	**4.98**	**6.48**		

Potential Emissions

Month	Incinerator #1 (Source ID 001) Operating Hours (hr)	Incinerator #2 (Source ID 002) Operating Hours (hr)	Incinerator #2 (Source ID 002) NOx Emissions[1] (tons)	Incinerator #1 (Source ID 001) NOx Emissions[1] (tons)
1/1/2024	744.00	744.00	5.58	5.58
2/1/2024	696.00	696.00	5.22	5.22
3/1/2024	744.00	744.00	5.58	5.58
4/1/2024	720.00	720.00	5.40	5.40
5/1/2024	744.00	744.00	5.58	5.58
6/1/2024	720.00	720.00	5.40	5.40
7/1/2024	744.00	744.00	5.58	5.58
8/1/2024	744.00	744.00	5.58	5.58
9/1/2024	720.00	720.00	5.40	5.40
10/1/2024	744.00	744.00	5.58	5.58
11/1/2024	720.00	720.00	5.40	5.40
12/1/2024	744.00	744.00	5.58	5.58
Totals[2]:	**8784.00**	**8784.00**	**65.88**	**65.88**

1. Potential NOx emissions based on Title V Operating Permit No. 23-00038 Incinerator NOx Emissions limitation of 15.0 lbNOx/hr
2. DELCORA is currently subject to a NOx Plant Wide Applicability Limit (PAL) of 82.560 tpy, and does not exceed this limit.

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 15.67 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 91,322,460 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 SO_2 emission rate: Not Applicable

Ash content (%Ash): 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, %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	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	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})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.19	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.016711648	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.00	

Plant Elevation	250	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	365	days
Estimated equipment life	20	Years

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: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016			
CEPCI for 2016	541.7	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.25	Percent		
Fuel ($Cost_{fuel}$)	2.97	$/MMBtu		
Reagent ($Cost_{reag}$)	0.29	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.1461	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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 ente[r] and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/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.	
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 *Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	16	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	132,884,027	scf/Year	
Actual Annual fuel consumption (Mactual) =		91,322,460	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.687	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	6020	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	91	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	2.65	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	7.97	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)			Not applicable; factor applies on fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	#VALUE!		Not applicable; factor applies on fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor apply to plants located at elevat 500 feet.
Atmospheric pressure at 250 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* 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	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	4	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	0.5	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	4,400	gallons (storage needed to store a 365 day reage 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	0.0962

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	0.2	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	1	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.01	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cos to coal-fired boilers

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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 ($SNCR_{cost}$) =	\$177,520 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	\$296,442 in 2016 dollars
Total Capital Investment (TCI) =	\$616,151 in 2016 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 ($SNCR_{cost}$) =	\$177,520 in 2016 dollars

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 2016 dollars

#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$296,442 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$10,441	in 2016 dollars
Indirect Annual Costs (IDAC) =	$59,551	in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$69,992	in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$9,242	in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$875	in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$147	in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$21	in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$156	in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2016 dollars
Direct Annual Cost =		$10,441	in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$277	in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$59,274	in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$59,551	in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$69,992	per year in 2016 dollars
NOx Removed =	8	tons/year
Cost Effectiveness =	$8,782	per ton of NOx removed in 2016 dollars

DELCORA, Chester PA
Emissions Summary

2024 Actual Emissions

Month	Incinerator #1 (Source ID 001) Sludge Processed (tons)	Incinerator #2 (Source ID 002) Sludge Processed (tons)	Total Sludge Processed (tons)	Incinerator #1 (Source ID 001) Natural Gas Usage (scf)	Incinerator #2 (Source ID 002) Natral Gas Usage (scf)	Incinerator #1 (Source ID 001) NOx Emissions (tons)	Incinerator #2 (Source ID 002) NOx Emissions (tons)	Incinerator #1 Emissions Rate (lb NOx/ton Sludge)	Incinerator #2 Emissions Rate (lb NOx/ton Sludge)	Incinerator #1 Emissions Rate (lb NOx/MMBtu)	Incinerator #2 Emissions Rate (lb NOx/MMBtu)
1/1/2024	853.80	652.80	1506.60	7797424.15	7212598.58	2.90	2.35	6.79	7.20	0.19	0.17
2/1/2024	629.50	933.50	1563.00	6915946.60	7761906.69	2.14	3.36	6.80	7.20	0.16	0.22
3/1/2024	713.70	1017.50	1731.20	6937540.29	7472652.19	2.43	3.66	6.81	7.19	0.18	0.25
4/1/2024	848.30	821.00	1669.30	8363288.47	5906905.19	2.88	2.96	6.79	7.21	0.18	0.26
5/1/2024	691.20	985.30	1676.50	8883490.09	7339197.35	2.35	3.55	6.80	7.21	0.14	0.25
6/1/2024	536.30	704.30	1240.60	5819370.00	6071450.00	1.82	2.54	6.79	7.21	0.16	0.22
7/1/2024	755.10	782.30	1537.40	8717874.64	8441500.00	1.52	2.32	4.03	5.93	0.09	0.14
8/1/2024	733.20	680.80	1414.00	6566046.00	5008939.94	1.10	1.92	3.00	5.64	0.09	0.20
9/1/2024	744.00	760.20	1504.20	6173371.27	8706967.23	1.12	2.15	3.01	5.66	0.09	0.13
10/1/2024	511.60	827.60	1339.20	6727444.76	8668119.87	0.83	2.34	3.24	5.65	0.06	0.14
11/1/2024	807.90	808.40	1616.30	8561479.88	9057045.49	1.21	2.28	3.00	5.64	0.07	0.13
12/1/2024	841.50	808.70	1650.20	10113899.02	9675177.66	1.26	2.28	2.99	5.64	0.06	0.12
Totals:	**8666.10**	**9782.40**	**18448.50**	**91577175.18**	**91322460.19**	**21.56**	**31.71**	**--**	**--**	**0.12**	**0.19**
							Average:	**4.98**	**6.48**		

Potential Emissions

Month	Incinerator #1 (Source ID 001) Operating Hours (hr)	Incinerator #2 (Source ID 002) Operating Hours (hr)	Incinerator #2 (Source ID 002) NOx Emissions[1] (tons)	Incinerator #1 (Source ID 001) NOx Emissions[1] (tons)
1/1/2024	744.00	744.00	5.58	5.58
2/1/2024	696.00	696.00	5.22	5.22
3/1/2024	744.00	744.00	5.58	5.58
4/1/2024	720.00	720.00	5.40	5.40
5/1/2024	744.00	744.00	5.58	5.58
6/1/2024	720.00	720.00	5.40	5.40
7/1/2024	744.00	744.00	5.58	5.58
8/1/2024	744.00	744.00	5.58	5.58
9/1/2024	720.00	720.00	5.40	5.40
10/1/2024	744.00	744.00	5.58	5.58
11/1/2024	720.00	720.00	5.40	5.40
12/1/2024	744.00	744.00	5.58	5.58
Totals[2]:	**8784.00**	**8784.00**	**65.88**	**65.88**

1. Potential NOx emissions based on Title V Operating Permit No. 23-00038 Incinerator NOx Emissions limitation of 15.0 lbNOx/hr
2. DELCORA is currently subject to a NOx Plant Wide Applicability Limit (PAL) of 82.560 tpy, and does not exceed this limit.