December 20, 2022

Ms. JoAnn Truchan, P.E.
Section Chief, Engineering
Allegheny County Health Department Air Quality Program
301 39th Street, Building #7
Pittsburgh, Pennsylvania 15201

Dear Ms. Truchan:

Subject: RACT III Case-by-Case Analysis Update
Energy Center Pittsburgh, LLC
ACHD Permit #: 0022-OP17e
CEC Project 181-975

Civil & Environmental Consultants, Inc. (CEC) on behalf of Energy Center Pittsburgh, LLC (ECP) is submitting this proposal to demonstrate compliance with the Reasonably Available Control Technology (RACT) requirements of 25 Pa. Code Sections §129.111 through §129.115 for their North Shore Plant (North Shore) located in Pittsburgh, Pennsylvania. The following proposal includes background information, a facility description, a summary of RACT affected sources and an updated limited case-by-case analysis per the requirements of §129.114(i) for sources that do not meet the presumptive RACT requirements of §129.112.

1.0 BACKGROUND AND FACILITY DESCRIPTION

On November 12, 2022, the Pennsylvania Department of Environmental Protection (PADEP) finalized amendments to 25 Pa. Code Chapters 121 (§121.1 relating to definitions) and 129 (§129.111 - §129.115), Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS (known as RACT III). The requirements of 25 Pa. Code §129.111 - §129.115 apply to owners and operators of all facilities in Pennsylvania that emit or have the potential to emit greater than 100 tons per year (tpy) of NOx and/or 50 tpy of VOCs.

An owner or operator subject to RACT III has three compliance options as follows:

1. Compliance with presumptive RACT requirements and/emissions limits of §129.112;

2. Facility-wide or system-wide averaging for compliance with presumptive NOx emissions limits per §129.113; or

3. Case-by-case RACT determinations for sources that either do not have an applicable presumptive requirements or emissions limitation or cannot comply with the applicable presumptive RACT requirement per §129.114. If a source was previously subject to a RACT II case-by-case determination, and that source has not been modified or changed,

the facility may, in lieu of doing another full case-by-case proposal for RACT III, submit a limited analysis as specified in §129.114(i).

North Shore is a commercial district heating and cooling plant located in the city of Pittsburgh, Allegheny County. North Shore is operated in accordance with Title V Operating Permit #0022-OP17e issued by the Allegheny County Health Department (ACHD) on August 25, 2017. The plant supplies steam for space heating and hospital sterilization and chilled water for refrigeration and summer air conditioning to commercial and institutional sites in that area. The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire No. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception of Boilers 4 and 5 which does not have the capability to fire No. 2 fuel oil. Boiler 5 is only used for emergency purposes and is located on the premises of Allegheny General Hospital. Additional equipment used for chilled water production includes various turbines, chillers and compressors, and cooling towers. The facility is considered a major source of NOx emissions; therefore, these combustion units must demonstrate compliance with RACT III requirements for sources of NOx emissions.

2.0 RACT AFFECTED SOURCES

Per 25 Pa. Code §129.111 and 129.115(a), an owner and operator of an air contamination source subject to the RACT III regulations must submit a notification describing how the facility intends to comply with the RACT III requirements, and other information identified in 25 Pa. Code §129.115(a).

On December 16, 2022, CEC on behalf of ECP submitted the required written notification of ECP's plan to demonstrate compliance with the RACT III requirements for North Shore. A copy of the written notification is included as Attachment A.

The following table (Table 1-1) illustrates the sources at North Shore subject to RACT III and the method used for demonstrating compliance with the RACT III requirements.

Table 1-1: Description of RACT Affected Units

Source ID	Source Description	Capacity	Fuel	RACT III Compliance Method
P001	Three Emergency Generators	350 kW; 250 kW & 250 kW	No. 2 fuel oil; Natural gas	Presumptive RACT requirement per §129.112(c)(10) for emergency engines operating less than 500 hours per year– installation, maintenance and operation in accordance with manufacturer's specifications and good operating practices

Source ID	Source Description	Capacity	Fuel	RACT III Compliance Method
B001	Babcock & Wilcox forced draft, water tube boiler	92 MMBtu/hr	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B002	Babcock & Wilcox forced draft, water tube boiler	92 MMBtu/hr	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B003	Babcock & Wilcox forced draft, water tube boiler	131.1 MMBtu/hr	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B004	Unilux forced draft, water tube boiler (with low-NOx burners)	24 MMBtu/hr	Natural gas	Presumptive RACT requirement per §129.112(b)(1)(ii) for combustion units with a rated heat input ≥ 20 MMBtu/hr and ≤ 50 MMBtu/hr with an oxygen trim system that maintains an optimum air-to-fuel ratio - conduct a tune-up of the boiler one time in each 5-year calendar period.
B005	Nebraska Boiler	46.08 MMBtu/hr	Natural gas	Presumptive RACT requirement per §129.112(c)(9) for fuel-burning unit with an annual capacity factor of < 5% – installation, maintenance and operation in accordance with manufacturer's specifications and good operating practices

North Shore previously demonstrated compliance with the requirements of 25 Pa. Code Chapter 129 (§129.96 - §129.100) "Additional RACT Requirements for Major Sources of NOx and VOCs" (known as RACT II) for the combustion sources located at the facility. Emergency Generators 1, 2 and 3 and Boilers 4 and 5 met the presumptive RACT II requirements of §129.97, which are the same as the presumptive RACT III requirements of §129.112 for these sources. For Boilers 1, 2 and 3, ACHD approved an alternative RACT II proposal. The RACT II requirements have been incorporated into the facility's Title V Operating Permit and are, therefore, federally enforceable.

Boilers 1, 2 and 3 have not been modified since the approved case-by-case RACT II proposal; therefore, ECP is submitting the following limited case-by-case RACT analysis per §129.114(i) to demonstrate compliance with RACT III for Boilers 1, 2 and 3.

3.0 LIMITED CASE-BY-CASE RACT ANALYSIS FOR BOILERS 1, 2 AND 3

According to §129.114(i), if a source was previously subject to a RACT II case-by-case determination, and that source has not been modified or changed, the facility may, in lieu of doing another full case-by-case proposal for RACT III, submit to the Department a limited analysis certified by the responsible official.

ECP previously demonstrated compliance with RACT II for Boilers 1, 2 and 3 with a case-by-case analysis approved by ACHD. The RACT II requirements have been incorporated into the facility's Title V Operating Permit. Boilers 1, 2 and 3 have not been modified since the RACT II analysis was completed and approved by the Department.

A copy of the case-by-case analysis completed to demonstrate compliance with RACT II for Boilers 1, 2 and 3 is included in Attachment B. The analysis considered the technical and economic feasibility of the following control technologies:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Flue Gas Recirculation (FGR)
- Burner Modification - Low NOx burners (LNB) and Ultra-Low NOx burners (ULNB)
- Low-Excess Air Firing
- Water/Steam Injection

The analysis concluded that the only technologies technically feasible for the boilers are FGR and burner modification (LNB and ULNB). ECP performed an economic analysis for these control options. As shown in Table 3 of the analysis, the cost effectiveness of these technologies was calculated to be greater than $7,500 per ton NOx removed, with the exception of Control Option 5 for Boiler 3. This control option considers the addition of FGR, new FD fan and a new ULNB. The cost effectiveness of this control option was calculated to be $7,247 per ton NOx removed.

Boilers 1, 2 and 3 have not been modified since the approved case-by-case RACT II proposal; therefore, ECP is submitting the following limited case-by-case RACT analysis per §129.114(i) to demonstrate compliance with RACT III for Boilers 1, 2 and 3. Because RACT II analysis showed a cost effectiveness greater than $7,500 per ton of NOx emissions removed for all control options for Boilers 1 and 2 and for control options 1 through 4 for Boiler 3, ECP may submit a limited case-by-case RACT analysis including the information required by §129.114(i)(1)(i) for these control options. For control option 5 for Boiler 5, because RACT II analysis showed a cost effectiveness less than $7,500 per ton of NOx emissions removed, ECP may submit a limited case-by-case RACT analysis including the information required by §129.114(i)(1)(ii), which includes an updated economic feasibility analysis for this control option.

To demonstrate compliance with RACT III for all control options for Boilers 1 and 2 and for control options 1 through 4 for Boiler 3, ECP is submitting this limited case-by-case RACT analysis. The following lists the information required by §129.114(i)(1)(i):

- *§129.114(i)(1)(i)(A): A statement that explains how the owner or operator determined that there is no new pollutant specific air cleaning device, air pollution control technology or technique available.*

  ECP Response: Boilers 1, 2, and 3 are conventional package boilers, which fire natural gas as their primary fuel and have the capacity to fire No. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment. Boilers 1 and 2 have a rated capacity of 92 MMBtu/hour each and Boiler 3 has a rated capacity of 131 MMBtu/hour. These boilers provide steam to a district energy system; customers connected to the system use the steam primarily for space heating. Summer operation of the boilers is required to operate steam driven chillers, which provide chilled water for cooling at customer locations. Boiler loads are relatively higher in the heating season.

  Available boiler control technologies are common and widely known. Boiler NOx control technologies are generally divided into combustion or post-combustion controls. Commonly applied combustion controls for industrial boilers are most effective at preventing the formation of thermal NOx by limiting peak flame temperatures; these technologies are not effective at preventing fuel NOx. Post-combustion controls can effectively reduce both thermal and fuel NOx because these controls are designed to remove NOx which is already present in the flue gases exiting the boiler.

  A review of the literature on NOx control and consultation with boiler equipment vendors has identified several possible control technologies that were evaluated in the RACT II analysis. No new control technologies have been developed since the RACT II analysis was completed.

- *§129.114(i)(1)(i)(B): A list of the technically feasible air cleaning devices, air pollution control technologies or techniques previously identified and evaluated under §129.92(b)(1)—(3) included in the written RACT proposal submitted under §129.99(d) and approved by the Department or appropriate approved local air pollution control agency under §129.99(e).*

  ECP Response: The RACT II analysis concluded that the only control technologies technically feasible for Boilers 1, 2 and 3 are FGR and burner modification (LNB and ULNB).

- *§129.114(i)(1)(i)(C): A summary of the economic feasibility analysis performed for each technically feasible air cleaning device, air pollution control technology or technique listed in clause (B) and the cost effectiveness of each technically feasible air cleaning device, air pollution control technology or technique as submitted previously under §129.99(d) or as* *calculated consistent with the ''EPA Air Pollution Control Cost Manual'' (6th Edition), EPA/452/B- 02-001, January 2002, as amended.*

ECP Response: The RACT II analysis concluded that the only technologies technically feasible for Boilers 1, 2 and 3 are FGR and burner modification (LNB and ULNB). ECP performed an economic analysis for these control options. The analysis is included in Attachment B. As shown in Table 3 of the analysis, the cost effectiveness for all control options for Boilers 1 and 2 and for control options 1 through 4 for Boiler 3 was calculated to be greater than $7,500 per ton NOx removed; therefore, these control options are cost prohibitive.

- *§129.114(i)(1)(i)(D): A statement that an evaluation of each economic feasibility analysis summarized in clause (C) demonstrates that the cost effectiveness remains equal to or greater than $7,500 per ton of NOx emissions reduced.*

  ECP Response: ECP performed an evaluation of cost effectiveness of each technically feasible control option consistent with the "OAQPS Control Cost Manual" (Sixth Edition), EPA 450/3-90-006 and material and labor costs provided by boiler vendors. The OAQPS Control Cost Manual has not been updated since the RACT II analysis was completed. In addition, based on discussions with vendors and inflation, the costs of materials and labor are expected to have increased since the RACT II analysis. Based on the expected increase in material and labor costs, the cost effectiveness of the control technologies evaluated remains greater than $7,500 per ton of NOx emissions reduced.

To demonstrate compliance with RACT III for control option 5 for Boiler 3, ECP is submitting this limited case-by-case RACT analysis per the requirements of §129.114(i)(1)(ii). The following lists the information required by §129.114(i)(1)(ii):

- *§129.114(i)(1)(ii)(A): A statement that explains how the owner or operator determined that there is no new pollutant specific air cleaning device, air pollution control technology or technique available.*

  ECP Response: Boiler 3 is a conventional package boiler, which fires natural gas as its primary fuel and has the capacity to fire No. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment. Boiler 3 has a rated capacity of 131 MMBtu/hour.

  Available boiler control technologies are common and widely known. Boiler NOx control technologies are generally divided into combustion or post-combustion controls. Commonly applied combustion controls for industrial boilers are most effective at preventing the formation of thermal NOx by limiting peak flame temperatures; these technologies are not effective at preventing fuel NOx. Post-combustion controls can effectively reduce both thermal and fuel NOx because these controls are designed to remove NOx which is already present in the flue gases exiting the boiler.

A review of the literature on NOx control and consultation with boiler equipment vendors has identified several possible control technologies that were evaluated in the RACT II analysis. No new control technologies have been developed since the RACT II analysis was completed.

- *§129.114(i)(1)(ii)(B): A list of the technically feasible air cleaning devices, air pollution control technologies or techniques previously identified and evaluated under §129.92(b)(1)—(3) included in the written RACT proposal submitted under §129.99(d) and approved by the Department or appropriate approved local air pollution control agency under §129.99(e).*

  ECP Response: The RACT II analysis concluded that the only control technologies technically feasible for Boiler 3 are FGR and burner modification (LNB and ULNB).

- *§129.114(i)(1)(ii)(C): A summary of the economic feasibility analysis performed for each technically feasible air cleaning device, air pollution control technology or technique listed in clause (B) and the cost effectiveness of each technically feasible air cleaning device, air pollution control technology or technique as submitted previously under §129.99(d) or as calculated consistent with the ''EPA Air Pollution Control Cost Manual'' (6th Edition), EPA/452/B- 02-001, January 2002, as amended.*

  ECP Response: The RACT II analysis concluded that the only technologies technically feasible for Boiler 3 are FGR and burner modification (LNB and ULNB). ECP performed an economic analysis for these control options. The analysis is included in Attachment B. As shown in Table 3 of the analysis, the cost effectiveness for control option 5 for Boiler 3 was calculated to be $7,247 per ton NOx removed; therefore, this control option was considered cost prohibitive.

- *§129.114(i)(1)(ii)(D): A statement that an evaluation of each economic feasibility analysis summarized in clause (C) demonstrates that the cost effectiveness remains less than $7,500 per ton of NOx emissions reduced.*

  ECP Response: ECP performed an updated economic feasibility analysis for Boiler 3 for the control option of adding new ULNB, new FD fan, FGR and damper/drive replacement. This control option was identified as control option 5 in the RACT II analysis. Please note per the boiler vendor, while this control option is a possible retrofit for Boiler 3, control options 2, 3 or 4 (as described in the RACT II analysis) are more common options. ULNB are very tightly controlled, are more susceptible to any upsets in the process and would bring more risk of success considering the age of the existing equipment.

  ECP performed an updated evaluation of cost effectiveness of this control option for Boiler 3 consistent with the "OAQPS Control Cost Manual" (Sixth Edition), EPA 450/3-90-006 and updated material and labor costs provided by the boiler vendor. The updated economic analysis including the boiler vendor quote is included in Attachment C. The updated evaluation shows a cost effectiveness of $6,994 per ton NOx reduced, which remains less than $7,500 per ton of NOx reduced.

- *§129.114(i)(1)(ii)(E): A new economic feasibility analysis for each technically feasible air cleaning device, air pollution control technology or technique listed in clause (B) in accordance with §129.92(b)(4).*

  ECP Response: ECP performed an updated economic feasibility analysis for Boiler 3 for the control option of adding new ULNB, new FD fan, FGR and damper/drive replacement. ECP performed the analysis consistent with the "OAQPS Control Cost Manual" (Sixth Edition), EPA 450/3-90-006 and subsequent revisions. The economic analysis along with vendor data used in the analysis is presented Attachment C, which includes the following tables:

  - Table 1 – Capital Cost Estimates
  - Table 2 – Annualized Cost Estimates
  - Table 3 – Cost-Effectiveness Estimates

  As shown in Table 3 of the economic analysis, the cost effectiveness of this control option for Boiler 3 is $6,994 per ton NOx reduced. According to the Preamble of RACT III, the cost-effectiveness benchmark for presumptive NOx RACT is $3,750/ton NOx. Based on this benchmark, ECP submits that the control option evaluated for Boiler 3 is cost prohibitive.

4.0 RACT PROPOSAL AND CONCLUSION

Based on the completed analysis, ECP is submitting the following proposal to demonstrate compliance with RACT III:

- P001, Emergency Generators 1, 2 and 3 – The engines meet the presumptive RACT requirement per §129.112(c)(10) for emergency engines operating less than 500 hours per year. The engines are installed, maintained and operated in accordance with manufacturer's specifications and good operating practices. The generators will continue to be subject to an operating restriction of 500 hours per year and fuel restrictions as incorporated in the facility's Title V Operating Permit.

- Boiler 4 – The boiler meets the presumptive RACT requirement per §129.112(b)(1)(ii) for combustion units with a rated heat input ≥ 20 MMBtu/hr and ≤ 50 MMBtu/hr with an oxygen trim system that maintains an optimum air-to-fuel ratio - conduct a tune-up of the boiler one time in each 5-year calendar period. The boiler will continue to be subject to fuel restrictions and a NOx emission rate of 0.038 lb/MMBtu per the facility's Title V Operating Permit.

- Boiler 5 – The boiler meets the presumptive RACT requirement per §129.112(c)(9) for fuel-burning unit with an annual capacity factor of < 5%. Boiler 5 is installed, maintained and operated in accordance with manufacturer's specifications and good operating practices. The boiler will continue to be subject to an operating restriction of 500 hours per year and fuel restrictions as incorporated in the facility's Title V Operating Permit.

- Boilers 1, 2 and 3 – In order to comply with the facility's RACT II proposal, ECP modified the facility's Title V Operating Permit to incorporate natural gas usage restrictions and annual NOx emission limits. To comply with RACT III, the facility will continue to comply with the following NOx emission and fuel restrictions as incorporated into the facility's Title V Operating Permit.

Table 4-1: Boilers 1, 2 and 3 Title V Operating Permit Restrictions

Source ID	NOx Emission Limitation		Natural Gas Usage Limit (MMScf/Year)
	lb/MMBtu	TPY	
Boiler 1	0.145	24.4	395
Boiler 2	0.145	36.7	514
Boiler 3	0.145	58.3	1,069

As required by §129.114(i), a certification of the RACT III analysis by the responsible official is included in Attachment D.

Please contact Matthew Brassard, Plant Manager, at 757-708-4179, or Amanda Black at 412-780-8698 or ablack@cecinc.com if you have any questions or require additional information.

Very truly yours,

CIVIL & ENVIRONMENTAL CONSULTANTS, INC.

Amber M. Isaac

Amber M. Isaac, P.E.
Project Manager

Amanda Black

Amanda Black
Principal

Enclosures

181-975-North Shore RACT III Updated Case-by-Case-12.20.22

ATTACHMENT A

WRITTEN NOTIFICATION FORM

December 16, 2022

Ms. JoAnn Truchan, P.E.
Section Chief, Engineering
Allegheny County Health Department Air Quality Program
301 39th Street, Building #7
Pittsburgh, Pennsylvania 15201

Dear Ms. Truchan:

Subject: RACT III Notification
Energy Center Pittsburgh, LLC
ACHD Permit #: 0022-OP17e
CEC Project 181-975

Civil & Environmental Consultants, Inc. (CEC) on behalf of Energy Center Pittsburgh, LLC (ECP) is submitting this written notification of their plan to demonstrate compliance with the Reasonably Available Control Technology (RACT) requirements of 25 Pa. Code Sections §129.111 through §129.115 for their North Shore Plant located in Pittsburgh, Pennsylvania.

On November 12, 2022, the Pennsylvania Department of Environmental Protection (PADEP) finalized amendments to 25 Pa. Code Chapters 121 (§121.1 relating to definitions) and 129 (§129.111 - §129.115), Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS (known as RACT III). The requirements of 25 Pa. Code §129.111 - §129.115 apply to owners and operators of all facilities in Pennsylvania that emit or have the potential to emit greater than 100 tons per year (tpy) of NOx and/or 50 tpy of VOCs. Per 25 Pa. Code §129.111 and 129.115(a), an owner and operator of an air contamination source subject to the final-form RACT III regulations must submit a notification describing how the facility intends to comply with the final-form RACT III requirements, and other information identified in 25 Pa. Code §129.115(a).

North Shore is a commercial district heating and cooling plant located in the city of Pittsburgh, Allegheny County. The plant supplies steam for space heating and hospital sterilization and chilled water for refrigeration and summer air conditioning to commercial and institutional sites in that area. The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire No. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception of Boilers 4 and 5 which does not have the capability to fire No. 2 fuel oil. Boiler 5 is only used for emergency purposes, and is located on the premises of Allegheny General Hospital. Additional equipment used for chilled water production includes various turbines, chillers and compressors, and cooling towers. The facility is considered a major source of NOx emissions; therefore, these combustion units must demonstrate compliance with RACT III requirements. As such, ECP is submitting this RACT III notification.

The attached RACT III written notification template as provided by the PADEP details how ECP intends to comply with RACT III. The attached form provides the information required by §129.115(a). In summary, Boilers 4 and 5 and Engines 1, 2 and 3 meet the presumptive RACT requirements of §129.112. For Boilers 1, 2 and 3, a case-by-case RACT analysis will be submitted.

Please contact Amanda Black at 412-780-8698 or ablack@cecinc.com if you have any questions or require additional information.

Very truly yours,

CIVIL & ENVIRONMENTAL CONSULTANTS, INC.

Amber M. Isaac

Amber M. Isaac, P.E.
Project Manager

Amanda Black

Amanda Black
Principal

Enclosures

181-975-North Shore RACT III Notification-12.16.22

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CHAPTER 129. STANDARDS FOR SOURCES ADDITIONAL RACT REQUIREMENTS FOR MAJOR SOURCES OF NOx AND VOCs FOR THE 2015 OZONE NAAQS

Written notification, 25 Pa. Code §§129.111 and 129.115(a)

25 Pa. Code Sections 129.111 and129.115(a) require that the owner and operator of an air contamination source subject to the final-form RACT III regulations submit a notification describing how you intend to comply with the final-form RACT III requirements, and other information spelled out in subsection 129.115(a). The owner or operator may use this template to notify DEP. Notification must be submitted in writing or electronically to the appropriate Regional Manager located at the appropriate DEP regional office. In addition to the notification required by §§ 129.111 and 129.115(a), you also need to submit an applicable analysis or RACT determination as per § 129.114(a) or (i).

Is the facility major for NOx?	**Yes** ☒ **No** ☐
Is the facility major for VOC?	**Yes** ☐ **No** ☒

FACILITY INFORMATION						
Facility Name	Energy Center Pittsburgh LLC – North Shore Plant					
Permit Number	ACHD Permit # 0022-OP17e	**PF ID if known**				
Address Line1	111 South Commons					
Address Line2						
City	Pittsburgh	**State**	PA	**Zip**	15212	
Municipality	City of Pittsburgh	**County**	Allegheny			
OWNER INFORMATION						
Owner	Energy Center Pittsburgh LLC					
Address Line1	111 South Commons					
Address Line2						
City	Pittsburgh	**State**	PA	**Zip**	15212	
Email	Matthew.Brassard@cordiaenergy.com	Phone	757-708-4179			
CONTACT INFORMATION						
Permit Contact Name	Matthew Brassard					
Permit Contact Title	Plant Manager					
Address Line	111 South Commons					
City	Pittsburgh	**State**	PA	**Zip**	15212	
Email	Matthew.Brassard@cordiaenergy.com	Phone	757-708-4179			

Complete Table 1, including all air contamination sources that commenced operation on or before August 3rd, 2018. Air contamination sources determined to be exempt from permitting requirements also must be included. You may find this information in section A and H of your operating permit.

Table 1 - Source Information

Source ID	Source Name	Make	Model	Physical location of a source (i.e, building#, plant#, etc.)	Was this source subject to RACT II?
P001	Three (3) Emergency Generators	Cummins	Unknown	Main Plant	Yes
B001	Boiler 1	Babcock & Wilcox	FM-1158	Main Plant	Yes
B002	Boiler 2	Babcock & Wilcox	FM-1158	Main Plant	Yes
B003	Boiler 3	Babcock & Wilcox	FM-2199	Main Plant	Yes
B004	Boiler 4	Unilux	Unknown	Main Plant	Yes
B005	Boiler 5	Nebraska	Unknown	Allegheny General Hospital	Yes
CT001	Main Cooling Tower	NA	NA	West of Main Plant	No
CT002	Annex Cooling Towers (No. 6 & 7)	NA	NA	West of Main Plant	No
Exempt	Three 25,000 gallon No. 2 Fuel Oil USTs	NA	NA	East of Main Plant	No

Complete Table 2 or 3 if the facility is a major NOx or VOC emitting facility. For the column with the title “How do you intend to comply”, compliance options are:

- Presumptive RACT requirement under §129.112 (**PRES**),
- Facility-wide averaging (**FAC**) §129.113,
- System-wide averaging (**SYS**) §129.113, or
- Case by case determination §129.114 (**CbC**).

Please provide the applicable subsection if source will comply with the presumptive requirement under §129.112.

Table 2 – Method of RACT III Compliance, NOx

Source ID	Source Name	NOx PTE TPY	Exempt from RACT III (yes or no)	How do you intend to comply? (PRES, CbC, FAC or SYS)	Specific citation of rule if presumptive option is chosen
P001	Three (3) Emergency Generators	6.17	No	PRES	§129.112(c)(10)
B001	Boiler 1	24.40	No	CbC	
B002	Boiler 2	36.70	No	CbC	
B003	Boiler 3	58.30	No	CbC	
B004	Boiler 4	4.00	No	PRES	§129.112(b)(1)(ii)
B005	Boiler 5	1.15	No	PRES	§129.112(c)(9)

Please complete Table 3 if the facility is a major VOC emitting facility. Please provide the applicable section if a source is complying with any RACT regulation listed in 25 Pa Code §§ 129.51, 129.52(a)—(k) and Table I categories 1—11, 129.52a—129.52e, 129.54—129.63a, 129.64—129.69, 129.71—129.73, 129.75 129.71—129.75, 129.77 and 129.101—129.107.

Table 3 – Method of RACT III Compliance, VOC

Source ID	Source Name	VOC PTE TPY	Exempt from RACT III (yes or no)	How do you intend to comply?	Specify citation of rule or subject to 25 Pa Code RACT regulation, (list the applicable sections)
NA					

ATTACHMENT B

APPROVED RACT II ANALYSIS

REASONABLY ACHIEVABLE CONTROL TECHNOLOGY (RACT) ANALYSIS

ENERGY CENTER PITTSBURGH LLC
NORTH SHORE PLANT

Prepared For:

ALLEGHENY COUNTY HEALTH DEPARTMENT
301 39TH STREET, BUILDING 7
PITTSBURGH, PENNSYLVANIA 15201

Submitted By:

ENERGY CENTER PITTSBURGH LLC – NORTH SHORE PLANT
111 SOUTH COMMONS
PITTSBURGH, PENNSYLVANIA 15212

Prepared By:

CIVIL & ENVIRONMENTAL CONSULTANTS, INC.
MONROEVILLE, PENNSYLVANIA

CEC Project 195-822

NOVEMBER 2019

TABLE OF CONTENTS

1.0 INTRODUCTION..1
1.1 Background and Purpose 1
1.2 Facility Description.. 2
1.3 RACT Affected Units 2

2.0 RACT ANALYSIS FOR BOILERS 1, 2 AND 3 5
2.1 RACT Methodology 5
2.2 Description of Baseline Conditions and Emissions 6
2.3 Background on Pollutant Formation... 7
2.4 Identification of Potential Control Techniques (Step 1) 7
2.4.1 Combustion Control Techniques 8
2.4.2 Post Combustion Control Methods..9
2.5 Elimination of Technically Infeasible Control Options (Step 2).......................... 10
2.6 Ranking of Remaining Control Options (Step 3) 11
2.7 Evaluation of Most Stringent Controls (Step 4) 11
2.8 Selection of RACT (Step 5).. 11

3.0 RACT PROPOSAL 12
3.1 Work Practices... 12
3.2 Restrictions 12
3.3 Testing Requirements 12
3.4 Monitoring, Recordkeeping and Reporting Requirements 12

APPENDICES

Appendix A RACT Economic Analysis
Appendix B Boiler Vendor Data

1.0 INTRODUCTION

1.1 BACKGROUND AND PURPOSE

Reasonably Achievable Control Technology (RACT) is defined by the U.S. Environmental Protection Agency (EPA) as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." The Federal Clean Air Act (CAA) requires a re-evaluation of RACT requirements each time the EPA promulgates a National Ambient Air Quality Standard (NAAQS). Because the ozone NAAQS was revised in 2008, a re-evaluation of RACT was necessary. RACT requirements apply statewide to the owner or operator of a major nitrogen oxides (NOx) emitting facility, a major volatile organic compound (VOC) emitting facility, or both, when the installation/modification of the source(s) occurred before July 20, 2012. NOx and VOC are pre-cursors to the formation of ozone.

As such, the Pennsylvania Department of Environmental Protection (PADEP) implemented regulations entitled, "Additional RACT Requirements for Major Sources of NOx and VOCs" (known as RACT II), which were promulgated by the Environmental Quality Board on April 23, 2016 (46 Pa.B. 2036). This regulation is referred to as RACT II, as the first round of RACT was implemented by PADEP in 1995. An owner or operator of a major NOx or a VOC emitting facility as defined in 25 Pa. Code §121.1 was to demonstrate compliance with the RACT II requirements by January 1, 2017.

An owner or operator subject to RACT II has three compliance options as follows:

1) Compliance with presumptive RACT requirements and/emissions limits;
2) Facility-wide or system-wide averaging for compliance with presumptive NOx emissions limits; or
3) Case-by-case RACT determinations for sources that either do not have an applicable presumptive requirements or emissions limitation or cannot comply with the applicable presumptive RACT requirement.

Energy Center Pittsburgh's (ECP) North Shore Plant (North Shore) is located in Allegheny County, Pennsylvania and is classified as a major source of NOx. Section 2105.06 of Allegheny County Health Department (ACHD) Rules and Regulations, Article XXI Air Pollution Control requires that RACT be applied to all major sources of NOx. ECP submitted a timely RACT II Rule Compliance Plan to ACHD for North Shore in April 2016, with a revision submitted on November 10, 2016. In the submitted RACT II Rule Compliance Plan, ECP proposed complying with the presumptive RACT for North Shore's three emergency generators (P001) and Boilers 4 and 5 (B004 and B005) and submitted a case-by-case RACT proposal for Boilers 1, 2, and 3 (B001, B002, and B003).

On October 18, 2019, ACHD issued a review letter with comments on the case-by-case RACT proposal for Boilers 1, 2 and 3. In the letter, ACHD identified specific points in the previous RACT Analysis that ACHD found in error or unwarranted. This revised RACT Analysis has been prepared to address ACHD's comments.

1.2 FACILITY DESCRIPTION

North Shore is a commercial district heating and cooling plant located at 111 South Commons in the North Shore section of Pittsburgh, PA. The plant supplies steam for space heating and hospital sterilization and chilled water for summer air conditioning to commercial and institutional sites in that area.

The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception of Boilers 4 and 5. Additional equipment used for chilled water production includes various turbines, chillers, compressors and cooling towers. The facility is a major source of NOx and carbon monoxide (CO) and minor source of particulate matter (PM), particulate matter < 10 microns in diameter (PM-10), sulfur dioxide (SO2), VOCs and hazardous air pollutants (HAPs) as defined in section 2101.20 of Article XXI.

1.3 RACT AFFECTED UNITS

As described in the RACT II Rule Compliance Plan submitted in 2016, the following table (Table 1-1) illustrates the sources at North Shore subject to RACT II and the method used for demonstrating compliance with the RACT II requirements.

Table 1-1: Description of RACT Affected Units

Source ID	Source Description	Capacity	Install Year	Fuel	RACT II Compliance Method
P001	Three Emergency Generators	350 kW; 250 kW & 250 kW	2004, 1999, 1972	No. 2 fuel oil; Natural gas	Presumptive RACT requirement per §129.97(c) for emergency engines operating less than 500 hours per year– installation, maintenance and operation in accordance with manufacturer's specifications and good operating practices
B001	Babcock & Wilcox forced draft, water tube boiler	92 MMBtu/hr	1967	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B002	Babcock & Wilcox forced draft, water tube boiler	92 MMBtu/hr	1967	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B003	Babcock & Wilcox forced draft, water tube boiler	131.1 MMBtu/hr	1971	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B004	Unilux forced draft, water tube boiler (with low-NOx burners)	24 MMBtu/hr	2001	Natural gas	Presumptive RACT requirement per §129.97(b)(2) for combustion units with a rated heat input ≥ 20 MMBtu/hr and ≤ 50 MMBtu/hr with an oxygen trim system that maintains an optimum air-to-fuel ratio - conduct a tune-up of the boiler one time in each 5-year calendar period.
B005	Nebraska Boiler	46.08 MMBtu/hr	2008	Natural gas	Presumptive RACT requirement per §129.97(c) for fuel-burning unit with an annual capacity factor of < 5% – installation, maintenance and operation in accordance with manufacturer's specifications and good operating practices

Boilers 1, 2 and 3 are capable of being fired with either natural gas (primary fuel) or No. 2 fuel oil as emergency / back-up fuel. Because No. 2 fuel oil will only be used in the event of an emergency, No. 2 fuel oil control technology was not evaluated for the boilers as a part of this analysis. NOx emissions from these boilers are determined by performance of a periodic compliance emissions test program. The most recent compliance test program was conducted in November 2017. The results from the test program, as compared to the presumptive RACT emission limits are summarized in the following table (Table 1-2).

Table 1-2: Boilers 1, 2 and 3 NOx Emission Rates

Source ID	NOx Emission Rates – Natural Gas Firing (lb/MMBtu)		
	2017 Stack Test Results	Title V Permit Limit	Presumptive RACT Limit
Boiler 1	0.121	0.145	0.10
Boiler 2	0.140	0.145	0.10
Boiler 3	0.107	0.145	0.10

Because these test results demonstrate that Boilers 1, 2 and 3 cannot meet the applicable presumptive RACT emission limitation, ECP has elected to demonstrate compliance using a case-by-case RACT. The case-by-case RACT analysis and proposal for Boilers 1, 2 and 3 is detailed in the following sections.

2.0 RACT ANALYSIS FOR BOILERS 1, 2 AND 3

2.1 RACT METHODOLOGY

As discussed in the previously submitted RACT II submittals and in Section 1.3, Boilers 1, 2 and 3 at North Shore do not meet the presumptive RACT NOx emission limit of 0.10 lb NOx/MMBtu for natural gas-fired combustion unit with a rated heat input greater than or equal to 50 MMBtu/hr. For sources that cannot comply with a presumptive RACT requirement and/or emissions limit, a case-by-case RACT II proposal must be developed in accordance with 25 Pa. Code §129.99(d); therefore, ECP is submitting a case-by-case RACT proposal for North Shore Boilers 1, 2 and 3. The RACT proposal must include the following information:

- A list of each air contamination source included in the RACT proposal (see Section 1.3, Table 1-1);
- The size or capacity of each affected source and the types of fuel combusted, or the types and quantities of materials processed or produced in each source (see Section 1.3, Table 1-1);
- A physical description of each source and its operating characteristics (see Section 1.3, Table 1-1);
- Estimates of the potential and actual NOx emissions from each affected source, and associated supporting documentation;
- The actual proposed alternative NOx RACT requirement or NOx RACT emissions limitation;
- A RACT analysis which meets the requirements of §129.92(b), including technical and economic support documentation for each affected source;
- A schedule for completing implementation of the RACT requirement or RACT emissions limitation;
- The intended testing, monitoring, recordkeeping, and reporting procedures proposed to demonstrate compliance with the proposed RACT requirement(s) and/or limitation(s); and,
- Additional information requested by the ACHD that is necessary for the evaluation of the RACT proposal.

Pursuant to 25 Pa. Code §129.92(b), the RACT analysis consists of a five-step, top-down, control technology feasibility analysis.

The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category for each regulated pollutant subject to review. If it can be shown this level of control is not technically or economically feasible, the next most stringent level of control is then determined and similarly evaluated. This process continues until a control technology and associated emission level is determined that cannot be eliminated by any technical, environmental, or economic objections. The five steps involved in a top down RACT analysis process are listed below:

Step 1 Identify all available control technologies for the source.
Step 2 Eliminate technically infeasible or commercially unavailable technology options.
Step 3 Rank the remaining control technologies by control effectiveness.
Step 4 Evaluate the most effective controls considering energy, environmental, economic, and other costs and document the results. If the top option is not selected as RACT, evaluate the next most effective control option.
Step 5 Select RACT.

2.2 DESCRIPTION OF BASELINE CONDITIONS AND EMISSIONS

Boilers 1, 2, and 3 are located in the main boiler plant located at 111 South Commons and are conventional package boilers. These boilers provide steam to a district energy system; customers connected to the system use the steam primarily for space heating. Summer operation of the boilers is required to operate steam driven chillers, which provide chilled water for cooling at customer locations. Boiler loads are relatively higher in the heating season.

NOx emission rates from these boilers are determined by performance of a periodic compliance emissions test program. According the facility's Title V Operating Permit, ECP must perform NOx emission testing on Boilers 1, 2 and 3 every two (2) years. Annual NOx emissions are calculated using the emission rates determined from the most recent stack tests and the fuel use for each boiler. These emissions are reported to the ACHD in the facility's annual emission inventory report.

In addition, the boilers are subject to NOx emission limitations as specified in the facility's Title V Operating Permit. The permitted emission limitations are based on potential to emit calculations, assuming that the boilers run 8,760 hours per year at full rated capacity.

Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline NOx emission rates (lbs/MMBtu) used in this analysis are the results from the most recent stack test performed on November 9, 2017.

As part of the RACT proposal as presented in Section 3, ECP is proposing to restrict natural gas consumed in Boiler 1 by 50 percent (%), Boiler 2 by 35% and Boiler 3 by 5% of the maximum boiler capacity. In order to annualize the baseline emissions rate, annual emissions were calculated using the proposed natural gas fuel limit. A summary of previously reported (Reporting Years 2017 and 2018) actual emissions and fuel usage and baseline emissions are summarized in the following table (Table 2-1).

Table 2-1: Boilers 1, 2 and 3 Annual Fuel Usage and NOx Emissions

Source ID	Capacity (MMBtu/hr)	Actual Emission Rate (lb/MMBtu)*	Fuel Usage (MMScf/Year)				Annual Emissions (TPY)			
			Permit Limit	2017 Actual	2018 Actual	Proposed Fuel Limit	Permit Limit	2017 Actual	2018 Actual	Baseline
Boiler 1	92	0.121	790	32	148	395	54.2	2.0	9.0	24.4
Boiler 2	92	0.140	790	132	267	514	54.2	9.4	18.9	36.7
Boiler 3	131.1	0.107	1,125	395	256	1,069	77.3	21.4	13.9	58.3

*Emission rates from stack test performed on November 9, 2017

2.3 BACKGROUND ON POLLUTANT FORMATION

NOx formation in combustion processes is generally believed to be the result of three different mechanisms producing "prompt NOx," "thermal NOx," and "fuel NOx." Prompt NOx is the result of intermediate combustion reactions involving nitrogen (N_2), oxygen (O_2) and hydrocarbons (CxHy). Thermal NOx is the result of N_2 and O_2 reactions occurring at high temperatures during the combustion process. Fuel NOx results from the oxidation of nitrogen compounds in the fuel itself.

Prompt NOx and thermal NOx reactions are temperature driven, with prompt NOx being the dominant mechanism at low temperatures and thermal NOx formation dominating at higher temperatures. Industrial combustion processes occur at relatively high temperatures thus making thermal NOx the more significant contributor under typical boiler operating conditions. U.S. EPA notes the "principal mechanism of NOx formation in natural gas combustion is thermal NOx" (see AP-42, §1.4.3). For purposes of this analysis, when natural gas is burned, it will be assumed that 100% of the NOx is the result of thermal NOx formation. Fuel NOx is nominally a function of fuel-bound nitrogen concentration, thus making it a less important reaction when low nitrogen fuels such as natural gas and No. 2 fuel oil are used.

2.4 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Boiler NOx control technologies are generally divided into combustion or post-combustion controls. Commonly applied combustion controls for industrial boilers are most effective at preventing the formation of thermal NOx by limiting peak flame temperatures; these technologies are not effective at preventing fuel NOx. Post-combustion controls can effectively reduce both thermal and fuel NOx because these controls are designed to remove NOx which is already present in the flue gases exiting the furnace.

A review of the literature on NOx control and consultation with boiler equipment vendors has identified several possible control technologies that could be applied to boilers similar to those installed at ECP. The descriptions in the following sections of this analysis have been taken from the "Boiler Emission Guide" published by Cleaver Brooks.

2.4.1 Combustion Control Techniques

"Combustion control techniques reduce the amount of NOx emission by limiting the amount of NOx formation during the combustion process. This is typically accomplished by lowering flame temperatures. Combustion control techniques are more economical than post-combustion methods and are frequently utilized on industrial boilers requiring NOx controls."

- Low excess air firing – "As a safety factor to assure complete combustion, boilers are fired with excess air. One of the factors influencing NOx formation in a boiler is the excess air levels. High excess air levels (greater than 45 percent) may result in increased NOx formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NOx. Low excess air firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra nitrogen and oxygen that enters the flame. Limiting the amount of excess air entering a flame is usually accomplished through burner design and can be optimized through the use of oxygen trim controls."

- Burner modifications – "Burner modifications for NOx control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NOx formation which, in turn, results in lower overall NOx emissions. The technology can be applied to most boiler types and sizes. It is most effective when firing natural gas and distillate fuel oil and has little effect on boilers firing heavy oil. To comply with the more stringent regulations, burner modifications must be used in conjunction with other NOx reduction methods, such as flue gas recirculation. If burner modifications are utilized exclusively to achieve low NOx levels, adverse effects on boiler operating parameters such as turndown, capacity, CO levels and efficiency may result."

- Water/Steam Injection – "Water or steam injection can be utilized to reduce NOx levels. By introducing water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NOx formation and overall NOx levels. Water or steam injection can reduce NOx up to 80 percent (when firing natural gas) and can result in lower reductions when firing oils. There is a practical limit to the amount of water or steam that can be injected into the flame before condensation problems are experienced. Additionally, under normal operating conditions, water/steam injection can result in a 3 to 10 percent efficiency loss. Many times water or steam injection is used in conjunction with other NOx control methods such as burner modifications or flue gas recirculation."

- Flue Gas Recirculation – "Flue gas recirculation, or FGR, is the most effective method of reducing NOx emissions from industrial boilers with inputs below 100 MMBtu/hr. FGR entails recirculating a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. It is currently the most effective and popular low NOx technology for firetube and watertube boilers. And, in many applications, it does not require any additional reduction equipment to comply with the most stringent regulations in the United States.

Flue gas recirculation technology can be classified into two types; external or induced. External flue gas recirculation utilizes an external fan to recirculate the flue gases back into the combustion zone. External piping routes the exhaust gases from the stack to the burner. A valve controls the recirculation rate, based on boiler input. Induced flue gas recirculation utilizes the combustion air fan to recirculate the flue gases back into the combustion zone. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are premixed with the combustion air and introduced into the flame through the burner. New designs of induced FGR that utilize an integral FGR design are becoming popular among boiler owners and operators because of their uncomplicated design and reliability.

Theoretically, there is no limit to the amount of NOx reduction with FGR; practically, there is a physical, feasible limit. The limit of NOx reduction varies for different fuels – 90 percent for natural gas and 25 to 30 percent for standard fuel oils. The current trends with low NOx technologies are to design the boiler and low NOx equipment as a package. Designing as a true package allows the NOx control technology to be specifically tailored to match the boiler's furnace design features, such as shape, volume, and heat release. By designing the low NOx technology as a package with the boiler, the effects of the low NOx technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized."

2.4.2 Post Combustion Control Methods

- Selective Non-Catalytic Reduction – "Selective non-catalytic reduction involves the injection of a NOx reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1,400 to 1,600 degrees Fahrenheit. The ammonia or urea breaks down the NOx in the exhaust gases into water and atmospheric nitrogen. Selective non-catalytic reduction reduces NOx up to 50 percent. However, the technology is extremely difficult to apply to industrial boilers that modulate frequently. This is because the ammonia (or urea) must be injected in the flue gases at a specific flue gas temperature. And in industrial boilers that modulate frequently, the location of the exhaust gases at the specified temperature is constantly changing. Thus, it is not feasible to apply selective non-catalytic reduction to industrial boilers that have high turndown capabilities and modulate frequently."

- Selective Catalytic Reduction – "Selective catalytic reduction involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NOx levels at lower exhaust temperatures than selective non-catalytic reduction. Unlike selective non-catalytic reduction, where the exhaust gases must be approximately 1,400 to 1,600 degrees Fahrenheit, selective catalytic reduction can be utilized where exhaust gases are between 500 and 1,200 degrees Fahrenheit, depending on the catalyst used. Selective catalytic reduction can result in NOx reductions up to 90 percent. However, it is costly to use and rarely can be cost justified on boilers with inputs less than 100 MMBtu/hour."

2.5 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

In this step, the control technologies identified in Step 1 are considered, and those which are clearly technically infeasible or have not been demonstrated (i.e., unavailable) are eliminated.

- Selective Catalytic Reduction – Although the technology can achieve very high levels of NOx control, the expected flue gas temperatures for Boilers 1, 2 and 3 are typically below the effective range required for the application of SCR controls. This control is being eliminated from further consideration on the basis that it is not technically feasible.

- Flue Gas Recirculation – FGR is a commonly applied technology which has been widely applied to industrial boilers, although the operating costs increase with recirculation rates as the increased flows require more energy to operate recirculation fans. This technology will be included for further analysis as it is widely applied on similar emission units and therefore considered feasible. The technology is an effective thermal NOx control.

- Selective Non-Catalytic Reduction – The narrative description presented above identifies problems with applying this technology to industrial boilers. Boilers that cycle and modulate, such as those used in heating applications, make it difficult to locate the necessary temperature zone for ammonia injection. This technology is being eliminated from further analysis for reasons stated previously in this narrative.

- Burner Modifications – Low NOx burners (LNB) and Ultra-Low NOx burners (ULNB) have been widely used in natural gas-fired boiler applications. The most effective control results when combining LNB/ULNB technology with other techniques such as FGR. The technology has been demonstrated to significantly reduce thermal NOx formation but is not expected to have a significant impact on fuel NOx formation.

- Low Excess Air Firing – The modest levels of reduction coupled with the already relatively low NOx levels permitted at North Shore make it unlikely that this technology would yield cost-effective benefits. An oxygen trim system that is designed to maintain an optimum air-to-fuel ratio is currently installed and operated on Boilers 1, 2 and 3. This technology will not be subject to additional review due to the very modest levels of control achievable; control of fuel NOx would be negligible

- Water/Steam Injection – NOx control can be extremely effective but high rates of injection adversely impact boiler efficiency thus limiting the practical use of this technology to achieve high levels of control. Because of the potential adverse impacts on boiler performance, and the availability of other technologies capable of similar or better levels of control, this technology will not be included for further analysis.

Based on the evaluations presented above, boiler vendor recommendations and a request from the ACHD, ECP has selected FGR and burner modification (LNB and ULNB) for further evaluation.

2.6 RANKING OF REMAINING CONTROL OPTIONS (STEP 3)

A ranking of the technically feasible control options in order of overall control effectiveness for NOx emissions is presented below. The following five NOx emissions control options were considered (listed in increasing order of control effectiveness):

- Control Option No. 1 – New LNB
- Control Option No. 2 – Re-use existing burner, re-use existing forced draft (FD) fan but install FGR. The amount of FGR would be limited by fan capacity.
- Control Option No. 3 - Add FGR and replace FD fan to allow greater percentage of FGR
- Control Option No. 4 - New LNB burner, new FD fan, FGR
- Control Option No. 5 - New ULNB, new FD fan, FGR, damper/drive replacement. Please note per the boiler vendor, while Option 5 is a possible retrofit for the existing boilers, Options 2, 3 or 4 are a more common option. ULNB are very tightly controlled, are more susceptible to any upsets in the process and would bring more risk of success considering the age of the existing equipment.

2.7 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

After ranking the technically feasible control technologies, the fourth step of the analysis is to evaluate the control options on the basis of economic, energy, and environmental considerations, and document the results. An evaluation of cost effectiveness of each control option consistent with the "OAQPS Control Cost Manual" (Sixth Edition), EPA 450/3-90-006 and subsequent revisions is presented Appendix A, which includes the following tables:

- Table 1 – Capital Cost Estimates
- Table 2 – Annualized Cost Estimates
- Table 3 – Cost-Effectiveness Estimates

Vendor data used in the cost analysis is included in Appendix B.

2.8 SELECTION OF RACT (STEP 5)

The presumptive RACT benchmark is $2,800/ton NOx. The RACT II preamble notes that a 25% buffer to the cost-effectiveness will not change the presumptive RACT determination. This buffer increases the presumptive RACT benchmark to $3,500/ton NOx. Based on this benchmark and because the average cost effectiveness values for all options evaluated are in excess of $8,000/ton NOx removed, ECP submits that the five evaluated control options are cost prohibitive. ECP requests approval of the RACT proposal detailed in Section 3.

3.0 RACT PROPOSAL

Based on the technology screening analysis and economic analysis completed, there are no source control or add-on NOx control technologies that are technologically feasible and cost effective for Boilers 1, 2 and 3. ECP is proposing to comply with RACT II for Boilers 1, 2 and 3 with a case-by-case RACT proposal. The proposed RACT requirements are as follows:

3.1 WORK PRACTICES

The facility will operate Boilers 1, 2 and 3 in accordance with good engineering practices.

3.2 RESTRICTIONS

The facility will operate in accordance with a Title V Operating Permit that restricts NOx emissions and natural gas fuel usage to the following permit limits:

Table 3-1: Boilers 1, 2 and 3 Title V Operating Permit Restrictions

Source ID	NOx Emission Limitation		Natural Gas Usage Limit (MMScf/Year)
	lb/MMBtu	TPY	
Boiler 1	0.145	54.2	395
Boiler 2	0.145	54.2	514
Boiler 3	0.145	77.3	1,069

NOx emission limitations will remain consistent with the current Title V Operating Permit emission restrictions per Conditions V.B.1.c and V.C.1c. The proposed natural gas usage restrictions will be incorporated into the Title V Operating Permit through a permit modification.

3.3 TESTING REQUIREMENTS

The facility will follow the testing requirements as listed in Sections V.B.2 and V.C.2 of the Title V Operating Permit.

3.4 MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS

ECP will continue to comply with the monitoring, recordkeeping and reporting requirements in accordance with the facility's existing Title V Operating Permit, as follows:

<u>Conditions V.B.4 and 5 (Boilers 1 and 2) and V.C.4 and 5 (Boiler 3)</u>

(1) Records of fuel consumption (daily, monthly, rolling 12-month recording basis)
(2) Records of operating hours (daily, monthly, rolling 12-month recording basis)
(3) Reports of fuel consumption (monthly and rolling 12-month totals)
(4) Reports of operating hours (monthly and rolling 12-month totals)

APPENDIX A

RACT ECONOMIC ANALYSIS

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boilers 1 and 2
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Costs								
Purchased Equipment (PE)	Vendor Quote x factor	1	$182,938	$119,742	$194,026	$376,964	$526,964	Input - B&W 2019 Vendor Quote
Freight	PE x factor	0.05	$9,147	$5,987	$9,701	$18,848	$26,348.20	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Total Purchased Equipment Costs (PEC)	Sum		$192,085	$125,729	$203,727	$395,812	$553,312	
Installation Costs	Vendor Quote	1	$110,872	$160,764	$232,831	$395,812	$435,394	Input - B&W 2019 Vendor Quote
Total Direct Costs (TDC)	Sum PEC + Installation Costs	1	$302,957	$286,493	$436,558	$791,624	$988,706	
Installation Costs, Indirect								
Engineering / supervision	TDC x factor	0.10	$30,296	$28,649	$43,656	$79,162	$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	$30,296	$28,649	$43,656	$79,162	$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	$30,296	$28,649	$43,656	$79,162	$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	$3,030	$2,865	$4,366	$7,916	$9,887.06	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		$12,000	$12,000	$12,000	$12,000	$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	$0	$0	$0	$0	$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	$60,591	$57,299	$87,312	$158,325	$197,741.24	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	$166,508	$158,111	$234,645	$415,728	$516,240	
Total Capital Investment (TCI)	Sum TDC + TIC	1	$469,465	$444,605	$671,203	$1,207,353	$1,504,946	

Notes:
1. The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:
   - NOx Control Option 1: New Low-NOx burner.
   - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
   - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
   - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
   - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The purchased equipment costs and direct installation costs were provided by the vendor.
4. The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
5. The factor used to determine the indirect installation cost for contingency was provided by the vendor.
6. The costs are the same for Boilers 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Costs								
Purchased Equipment (PE)	Vendor Quote x factor	1	$194,026	$119,742	$210,656	$404,682	$554,682	Input - B&W 2019 Vendor Quote
Freight	PE x factor	0.05	$9,701	$5,987	$10,533	$20,234	$27,734.10	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Total Purchased Equipment Costs (PEC)	Sum		$203,727	$125,729	$221,189	$424,916	$582,416	
Installation Costs	Vendor Quote	1	$110,872	$160,764	$252,788	$426,856	$469,542	Input - B&W 2019 Vendor Quote
Total Direct Costs (TDC)	Sum PEC + Installation Costs	1	$314,599	$286,493	$473,977	$851,772	$1,051,958	
Installation Costs, Indirect								
Engineering / supervision	TDC x factor	0.10	$31,460	$28,649	$47,398	$85,177	$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	$31,460	$28,649	$47,398	$85,177	$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	$31,460	$28,649	$47,398	$85,177	$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	$3,146	$2,865	$4,740	$8,518	$10,520	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		$12,000	$12,000	$12,000	$12,000	$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	$0	$0	$0	$0	$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	$62,920	$57,299	$94,795	$170,354	$210,391.62	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	$172,446	$158,111	$253,728	$446,404	$548,499	
Total Capital Investment (TCI)	Sum TDC + TIC	1	$487,045	$444,605	$727,705	$1,298,176	$1,600,457	

Notes:
1. The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:
   - NOx Control Option 1: New Low-NOx burner.
   - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
   - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
   - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
   - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The purchased equipment costs and direct installation costs were provided by the vendor.
4. The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
5. The factor used to determine the indirect installation cost for contingency was provided by the vendor.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 1
Table 2 - Annualized Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Operating Costs								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$4,063	$4,063	$4,063	$4,063	$4,063	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Operating Labor - Supervision	OL x factor	0.15	$609.38	$609	$609	$609	$609	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$4,063	$4,063	$4,063	$4,063	$4,063	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Maintenance Materials	100% of ML	1	$4,063	$4,063	$4,063	$4,063	$4,063	OAQPS Control Cost Manual
Utilities - Electricity								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	$0	$986	$3,566	$3,566	$3,566	factor = typical electricity cost ($/KWh)
Total Direct Operating Costs (DOC)	Sum		$12,797	$13,783	$16,363	$16,363	$16,363	
Indirect Operating Costs								
Overhead	(OL + ML) x factor	0.60	$4,875	$4,875	$4,875	$4,875	$4,875	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	$4,695	$4,446	$6,712	$12,074	$15,049	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	$9,389	$8,892	$13,424	$24,147	$30,099	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	$51,543	$48,813	$73,691	$132,555	$165,228	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		$70,502	$67,026	$98,702	$173,651	$215,251	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	$83,298	$80,809	$115,065	$190,014	$231,614	

Notes:
1. The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:
   - NOx Control Option 1: New Low-NOx burner.
   - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
   - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
   - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
   - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The direct operating costs use the following assumptions:
   - Operating hours per year 1000 operating hours / yr
   - Equivalent shifts per year 125
4. The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
5. The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P \; * s * \theta * p_e}{6356 * \eta}$$

Where:
- Q = gas flow rate (acfm)
- P = pressure drop through system (in. H2O)
- s = specific gravity of gas relative to air
- θ = operating factors (hr/yr)
- η = combined fan and motor efficiency (usually 0.6 to 0.7)
- p_e = electricity cost ($/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:
Option 1: There is no additional fan power associated with the low-NOx burner.
Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	38,197	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	8,966	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	38,197	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	32,417	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	$i(1+i)^n / ((1+i)^n-1)$
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 2
Table 2 - Annualized Cost Estimates **

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Operating Costs								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$20,313	$20,313	$20,313	$20,313	$20,313	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Operating Labor - Supervision	OL x factor	0.15	$3,047	$3,047	$3,047	$3,047	$3,047	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$20,313	$20,313	$20,313	$20,313	$20,313	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Maintenance Materials	100% of ML	1	$20,313	$20,313	$20,313	$20,313	$20,313	OAQPS Control Cost Manual
Utilities - Electricity								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	$0	$3,458	$12,501	$12,501	$12,501	Factor = typical electricity cost ($/KWh)
Total Direct Operating Costs (DOC)	Sum		$63,984	$67,442	$76,486	$76,486	$76,486	
Indirect Operating Costs								
Overhead	(OL + ML) x factor	0.60	$24,375	$24,375	$24,375	$24,375	$24,375	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	$4,695	$4,446	$6,712	$12,074	$15,049	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	$9,389	$8,892	$13,424	$24,147	$30,099	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	$51,543	$48,813	$73,691	$132,555	$165,228	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		$90,002	$86,526	$118,202	$193,151	$234,751	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	$153,986	$153,969	$194,688	$269,637	$311,237	

Notes:
1. The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:

NOx Control Option 1:	New Low-NOx burner.
NOx Control Option 2:	Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
NOx Control Option 3:	Add FGR and replace FD fan to allow greater % of flue gas recirculation.
NOx Control Option 4:	New Low-NOx burner, new FD fan, flue gas recirculation.
NOx Control Option 5:	New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.

3. The direct operating costs use the following assumptions:

Operating hours per year	5000	operating hours / yr
Equivalent shifts per year	625	

4. The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.

5. The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P \ * s * \theta * p_e}{6356 * \eta}$$

Where:
- Q = gas flow rate (acfm)
- P = pressure drop through system (in. H2O)
- s = specific gravity of gas relative to air
- θ = operating factors (hr/yr)
- η = combined fan and motor efficiency (usually 0.6 to 0.7)
- p_e = electricity cost ($/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:
Option 1: There is no additional fan power associated with the low-NOx burner.
Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	26,783	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	31,435	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	26,783	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	113,650	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	$i(1+i)^n / ((1+i)^n-1)$
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 2 - Annualized Cost Estimates **

			Costs for Each NOx Control Option					
Cost Item	Computation Method	Factor	Option 1	Option 2	Option 3	Option 4	Option 5	Notes
Direct Operating Costs								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$28,438	$28,438	$28,438	$28,438	$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Operating Labor - Supervision	OL x factor	0.15	$4,266	$4,266	$4,266	$4,266	$4,266	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$28,438	$28,438	$28,438	$28,438	$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Maintenance Materials	100% of ML	1	$28,438	$28,438	$28,438	$28,438	$28,438	OAQPS Control Cost Manual
Utilities - Electricity								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	$0	$7,699	$27,834	$27,834	$27,834	Factor = typical electricity cost ($/KWh)
Total Direct Operating Costs (DOC)	Sum		$89,578	$97,277	$117,412	$117,412	$117,412	
Indirect Operating Costs								
Overhead	(OL + ML) x factor	0.60	$34,125	$34,125	$34,125	$34,125	$34,125	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	$4,870	$4,446	$7,277	$12,982	$16,005	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	$9,741	$8,892	$14,554	$25,964	$32,009	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	$53,473	$48,813	$79,895	$142,527	$175,714	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		$102,209	$96,276	$135,851	$215,597	$257,853	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	$191,787	$193,553	$253,263	$333,009	$375,265	

Notes:
1. The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:

NOx Control Option 1:	New Low-NOx burner.
NOx Control Option 2:	Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
NOx Control Option 3:	Add FGR and replace FD fan to allow greater % of flue gas recirculation.
NOx Control Option 4:	New Low-NOx burner, new FD fan, flue gas recirculation.
NOx Control Option 5:	New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.

3. The direct operating costs use the following assumptions:

Operating hours per year	7000	operating hours / yr
Equivalent shifts per year	875	

4. The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.

5. The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:
- Q = gas flow rate (acfm)
- P = pressure drop through system (in. H2O)
- s = specific gravity of gas relative to air
- θ = operating factors (hr/yr)
- η = combined fan and motor efficiency (usually 0.6 to 0.7)
- p_e = electricity cost ($/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:
Option 1: There is no additional fan power associated with the low-NOx burner.
Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	42,593	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	69,988	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	42,593	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	253,032	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	$i(1+i)^n / ((1+i)^n-1)$
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 1
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel[1]	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr)[2]	Fuel Use with Restriction (MMScf/Yr)[3]	Current NOx Emission Rate (lb/MMBtu)[4]	Baseline NOx Emissions (tons/yr)[5]	Controlled NOx Emission Rate (lb/MMBtu)[6]	NOx Emissions Post-Control (tons/yr)[7]	Total Annualized Cost ($/yr)[8]	Cost Effectiveness ($ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	92	790	395	0.121	24.4	0.100	20.1	$83,298	$19,687	
2	FGR with existing FD Fan	Natural Gas	92	790	395	0.121	24.4	0.100	20.1	$80,809	$19,099	Infinite
3	FGR + FD fan	Natural Gas	92	790	395	0.121	24.4	0.050	10.1	$115,065	$8,044	$3,400
4	FGR + FD fan + LNB	Natural Gas	92	790	395	0.121	24.4	0.036	7.3	$190,014	$11,095	$26,571
5	FGR + FD fan + ULNB	Natural Gas	92	790	395	0.121	24.4	0.012	2.4	$231,614	$10,546	$8,603

Notes:
1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to "a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil."
2. Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
3. RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 50%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
4. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
5. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
6. Post-control NOx emission rates are vendor guarantees for natural gas firing.
7. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
8. Annualized costs are summarized here and were calculated in Tables 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 2
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel[1]	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr)[2]	Fuel Use with Restriction (MMScf/Yr)[3]	Current NOx Emission Rate (lb/MMBtu)[4]	Baseline NOx Emissions (tons/yr)[5]	Controlled NOx Emission Rate (lb/MMBtu)[6]	NOx Emissions Post-Control (tons/yr)[7]	Total Annualized Cost ($/yr)[8]	Cost Effectiveness ($ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	92	790	514	0.14	36.7	0.100	26.2	$153,986	$14,698	
2	FGR with existing FD Fan	Natural Gas	92	790	514	0.14	36.7	0.100	26.2	$153,969	$14,696	Infinite
3	FGR + FD fan	Natural Gas	92	790	514	0.14	36.7	0.050	13.1	$194,688	$8,259	$3,109
4	FGR + FD fan + LNB	Natural Gas	92	790	514	0.14	36.7	0.036	9.4	$269,637	$9,899	$20,439
5	FGR + FD fan + ULNB	Natural Gas	92	790	514	0.14	36.7	0.012	3.1	$311,237	$9,283	$6,618

Notes:

1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to “a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil.”
2. Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
3. RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 35%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
4. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
5. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
6. Post-control NOx emission rates are vendor guarantees for natural gas firing.
7. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
8. Annualized costs are summarized here and were calculated in Tables 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel[1]	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr)[2]	Fuel Use with Restriction (MMScf/Yr)[3]	Current NOx Emission Rate (lb/MMBtu)[4]	Baseline NOx Emissions (tons/yr)[5]	Controlled NOx Emission Rate (lb/MMBtu)[6]	NOx Emissions Post-Control (tons/yr)[7]	Total Annualized Cost ($/yr)[8]	Cost Effectiveness ($ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	131.1	1125	1069	0.107	58.3	0.100	54.5	$191,787	$50,266	
2	FGR with existing FD Fan	Natural Gas	131.1	1125	1069	0.107	58.3	0.100	54.5	$193,553	$50,729	Infinite (neg.)
3	FGR + FD fan	Natural Gas	131.1	1125	1069	0.107	58.3	0.050	27.3	$253,263	$8,152	$2,191
4	FGR + FD fan + LNB	Natural Gas	131.1	1125	1069	0.107	58.3	0.036	19.6	$333,009	$8,605	$10,450
5	FGR + FD fan + ULNB	Natural Gas	131.1	1125	1069	0.107	58.3	0.012	6.5	$375,265	$7,247	$3,230

Notes:

1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to "a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil."
2. Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
3. RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 5%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
4. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
5. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
6. Post-control NOx emission rates are vendor guarantees for natural gas firing.
7. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
8. Annualized costs are summarized here and were calculated in Tables 1 and 2.

APPENDIX B

BOILER VENDOR DATA

BABCOCK & WILCOX

The Babcock & Wilcox Company

277 Fairfield Road · Suite 331A · Fairfield, NJ 07004
Phone 973.227.7008 · Fax 973.227.7009 · www.babcock.com

Nov 13, 2019

Via Email

Clearway Energy, Inc.
111 South Commons Ave
Pittsburgh, PA 15212

Attn: Mr. Bard Rupp

Re: Orig. B&W Contract FM-1158 (2 boilers) & FM-2199
Subj: RACT 2 Filing Analysis Support

Dear Mr. Rupp:

Following our conversation last week regarding your upcoming RACT 2 filing, we wanted to summarize the analysis we completed related to NOx control technologies that could be available to the three referenced B&W boilers at your Pittsburgh steam plant. This analysis was a continuation of similar work we did for this facility in 2016. There are a number of NOx reduction strategies that can be used depending on existing equipment arrangement, the fuel being burned, NOx target levels and of course project costs. The following is a summary of the options reviewed:

Option 1: New Low-NOx burner.

Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.

Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.

Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.

Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements

The attached spreadsheet summarizes the predicted NOx reduction from each of the strategies listed above. The sheet also includes estimated material and installation costs. I should note that while Option 5 is likely possible to retrofit on the existing boilers, we typically see requests for Options 2, 3 or 4. Ultra-Low-NOx burners are very tightly controlled, are more suspectable to any upsets in the process and would bring more risk of success considering the age of the existing equipment.

If we can be of further assistance please do not hesitate to contact me at 603-498-1207 or via e-mail at ladimke@babcock.com.

Sincerely,

Luke Dimke – District Engineer - Northeast

Clearway Energy Pittsburgh Steam Plant 11/13/2019

FM-1158 (2 Units)	NOx	Units	NOx	Units	% FGR	Equipment Required	Material	Labor	Total
							Pricing is estimated +/- 20%		
Natural Gas - Case 1	0.100	LB/MMBTU	82	PPM*	0	New Burner	$182,938	$110,872	$293,810
Natural Gas - Case 2	0.100	LB/MMBTU	82	PPM*	4.5	FGR Duct	$119,742	$160,764	$280,506
Natural Gas - Case 3	0.050	LB/MMBTU	41	PPM*	15	FD Fan/FGR Duct	$194,026	$232,831	$426,856
Natural Gas - Case 4	0.036	LB/MMBTU	30	PPM*	15	Burner/FD Fan/FGR Duct	$376,964	$395,812	$772,776
Natural Gas - Case 5	0.012	LB/MMBTU	10	PPM*	30	Burner/FD Fan/FGR Duct	$526,964	$435,394	$962,358

* Corrected to 3% O2 Dry

FM-2199	NOx	Units	NOx	Units	% FGR	Equipment Required	Material	Labor	Total
							Pricing is estimated +/- 20%		
Natural Gas - Case 1	0.100	LB/MMBTU	82	PPM*	0	New Burner	$194,026	$110,872	$304,897
Natural Gas - Case 2	0.100	LB/MMBTU	82	PPM*	4.5	FGR Duct	$119,742	$160,764	$280,506
Natural Gas - Case 3	0.050	LB/MMBTU	41	PPM*	15	FD Fan/FGR Duct	$210,656	$252,788	$463,444
Natural Gas - Case 4	0.036	LB/MMBTU	30	PPM*	15	Burner/FD Fan/FGR Duct	$404,682	$426,856	$831,538
Natural Gas - Case 5	0.012	LB/MMBTU	10	PPM*	30	Burner/FD Fan/FGR Duct	$554,682	$469,542	$1,024,224

* Corrected to 3% O2 Dry

All Three Units	Equipment Required	Material	Labor	Total
		Pricing is estimated +/- 20%		
Natural Gas - Case 1	New Burner	$559,903	$332,615	$892,518
Natural Gas - Case 2	FGR Duct	$359,225	$482,292	$841,517
Natural Gas - Case 3	FD Fan/FGR Duct	$598,708	$718,449	$1,317,157
Natural Gas - Case 4	Burner/FD Fan/FGR Duct	$1,158,610	$1,218,481	$2,377,091
Natural Gas - Case 5	Burner/FD Fan/FGR Duct	$1,608,610	$1,340,329	$2,948,939

ATTACHMENT C

ECONOMIC FEASIBILITY ANALYSIS

Energy Center Pittsburgh
PA DEP RACT III Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Control Option 5	Notes
Direct Costs				
Purchased Equipment (PE)	Vendor Quote x factor	1	$657,500	Input - B&W 2022 Vendor Quote
Freight	PE x factor	0.05	$32,875.00	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Total Purchased Equipment Costs (PEC)	Sum		$690,375	
Installation Costs	Vendor Quote	1	$556,500	Input - B&W 2022 Vendor Quote
Total Direct Costs (TDC)	Sum PEC + Installation Costs	1	$1,246,875	
Installation Costs, Indirect				
Engineering / supervision	TDC x factor	0.10	$124,688	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	$124,688	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	$124,688	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	$12,469	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	$249,375.00	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	$647,906	
Total Capital Investment (TCI)	Sum TDC + TIC	1	$1,894,781	

Notes:
1. The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:
   NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The purchased equipment costs and direct installation costs were provided by the vendor.
4. The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
5. The factor used to determine the indirect installation cost for contingency was provided by the vendor.

Energy Center Pittsburgh
PA DEP RACT III Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 2 - Annualized Cost Estimates **

Cost Item	Computation Method	Factor	Control Option 5	Notes
Direct Operating Costs				
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Operating Labor - Supervision	OL x factor	0.15	$4,266	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate ($/hr)
Maintenance Materials	100% of ML	1	$28,438	OAQPS Control Cost Manual
Utilities - Electricity				
Additional Fan Power	Calculation - see below	1		OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	$34,647	Factor = typical electricity cost ($/KWh)
Total Direct Operating Costs (DOC)	Sum		$124,225	
Indirect Operating Costs				
Overhead	(OL + ML) x factor	0.60	$34,125	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	$18,948	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	$37,896	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	$208,028	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		$298,996	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	$423,221	

Notes:
1. The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:
NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The direct operating costs use the following assumptions:

Operating hours per year	7000
Equivalent shifts per year	875

4. The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
5. The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P \ * s * \theta * p_e}{6356 * \eta}$$

Where:
Q = gas flow rate (acfm)
P = pressure drop through system (in. H2O)
s = specific gravity of gas relative to air
θ = operating factors (hr/yr)
η = combined fan and motor efficiency (usually 0.6 to 0.7)
p_e = electricity cost ($/kw-hr)

The direct costs related to utilities for Option 5 are shown below:

Gas flow rate, Q (acfm)	53,019	per 2019 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	314,970	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	$i(1+i)^n / ((1+i)^n-1)$
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT III Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel[1]	Boiler Capacity (MMBtu/hr)	Maximum Permitted Natural Gas Burned (MMScf/Yr)[2]	Current NOx Emission Rate (lb/MMBtu)[3]	Baseline NOx Emissions (tons/yr)[4]	Controlled NOx Emission Rate (lb/MMBtu)[5]	NOx Emissions Post-Control (tons/yr)[6]	Total Annualized Cost ($/yr)[7]	Cost Effectiveness ($ / ton NOx Reduced) Average
5	FGR + FD fan + ULNB	Natural Gas	131.1	1069	0.123	67.1	0.012	6.5	$423,221	$6,994

Notes:

1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to “a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil.”
2. Maximum permitted annual natural gas usage per Title V operating permit #0022.
Natural Gas Heating Value (Btu/scf): 1020
3. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 12/11/2019.
4. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
5. Post-control NOx emission rates are vendor guarantees for natural gas firing.
6. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
7. Annualized costs are summarized here and were calculated in Tables 1 and 2.

Cordia Energy - Pittsburgh Steam Plant **12/7/2022**

							Budget Pricing		
FM-1158 (2 Units)	NOx	Units	NOx	Units	% FGR	Equipment Required	Material	Labor	Total
Natural Gas - Case 1	0.100	LB/MMBTU	82	PPM*	0	New Burner			
Natural Gas - Case 2	0.100	LB/MMBTU	82	PPM*	4.5	FGR Duct			
Natural Gas - Case 3	0.050	LB/MMBTU	41	PPM*	15	FD Fan/FGR Duct			
Natural Gas - Case 4	0.036	LB/MMBTU	30	PPM*	15	Burner/FD Fan/FGR Duct			
Natural Gas - Case 5	0.012	LB/MMBTU	10	PPM*	30	Burner/FD Fan/FGR Duct	$624,500	$516,000	$1,140,500
* Corrected to 3% O2 Dry									
							Budget Pricing		
FM-2199	NOx	Units	NOx	Units	% FGR	Equipment Required	Material	Labor	Total
Natural Gas - Case 1	0.100	LB/MMBTU	82	PPM*	0	New Burner			
Natural Gas - Case 2	0.100	LB/MMBTU	82	PPM*	4.5	FGR Duct			
Natural Gas - Case 3	0.050	LB/MMBTU	41	PPM*	15	FD Fan/FGR Duct			
Natural Gas - Case 4	0.036	LB/MMBTU	30	PPM*	15	Burner/FD Fan/FGR Duct			
Natural Gas - Case 5	0.012	LB/MMBTU	10	PPM*	30	Burner/FD Fan/FGR Duct	$657,500	$556,500	$1,214,000
* Corrected to 3% O2 Dry									

ATTACHMENT D

CERTIFICATION

TRUTH, ACCURACY, AND COMPLETENESS CERTIFICATION BY RESPONSIBLE OFFICIAL	
I certify that, based on information and belief formed after reasonable inquiry, the statements and information contained in the attached RACT III case-by-case proposal are true, accurate and complete.	
Signature	Date 12/20/2022
Responsible Official Name	Matthew Brassard
Responsible Official Title	Plant Manager