# ALLEGHENY COUNTY HEALTH DEPARTMENT
# AIR QUALITY PROGRAM

January 28, 2021

**SUBJECT**: U. S. Steel Clairton Works
Installation Permit: No. 0052-I019

This permit is for the installation of a Cogeneration Plant

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## FACILITY DESCRIPTION

U. S. Steel Mon Valley Works Clairton Plant is the largest by-products coke plant in North America. The Clairton Plant operates 10 coke batteries and produces approximately 13,000 tons of coke per day from the destructive distillation (carbonization) of more than 18,000 tons of coal. During the carbonization process, approximately 225 million cubic feet of coke oven gas are produced. The volatile products of coal contained in the coke oven gas are recovered in the by-products plant. In addition to the coke oven gas, daily production of these by-products includes 145,000 gallons of crude coal tar, 55,000 gallons of light oil, 35 tons of elemental sulfur, and 50 tons of anhydrous ammonia. The coke produced is used in the blast furnace operations in the production of molten iron for steel making.

Clairton Works is located approximately 20 miles south of Pittsburgh on 392 acres along 3.3 miles of the west bank of the Monongahela River. The plant was built by St. Clair Steel Company in 1901 and bought by U. S. Steel in 1904. The first coke batteries were built in 1918. The coke produced is used in the blast furnace operations in the production of molten iron for steel making.

## INSTALLATION DESCRIPTION

This is an installation of a new combined heat and power process (Cogeneration Project) at the Clairton Plant. The Cogeneration Project is an energy efficient integrated combined heat and power process to generate electricity as well as steam to support the industrial processes of U.S. Steel's Mon Valley Works complex. The Cogeneration Project will be configured with two (2) identical trains, each with a combustion turbine followed by a heat recovery steam generating (HRSG) unit (i.e., with duct burners). Each train will have a nominal heat input rating of 637 MMBtu/hr for the combustion turbine and 434 MMBtu/hr for the HRSG duct burner, with an electrical generation output capacity of approximately 47 megawatts (MW). The units will be designed to be fired primarily with coke oven gas (COG), with the capability to fire natural gas as an alternative. The units may on occasion be fired with a blend of COG and natural gas. Following the final commissioning of both the new cogeneration units, existing boilers (Boiler 1, Boiler 2, and Boiler R-1) at the Clairton Plant will be permanently shut down. The three remaining boilers (Boiler R-2, Boiler T-1, and Boiler T-2) will only be operated on a limited basis as needed to meet plant steam demands. In addition, the Clairton Plant is expected to be electrically independent, and/or may be a net exporter of electricity following the project, thereby significantly reducing the carbon footprint of the Mon Valley Works overall.

The Cogeneration Project is designed to utilize multiple state-of-the-art air pollution control techniques to minimize emissions of various pollutants. The use of water injection and selective catalytic reduction (SCR) will control $NO_X$ emissions. The units will also be equipped with oxidation catalysts to minimize emissions of CO and VOC. $SO_2$ emissions will be reduced through the use of a wet scrubber. Finally, the exhaust will be routed through a wet electrostatic precipitator (Wet ESP) to minimize particulate matter emissions. As an alternate, and equivalent, control configuration the permit includes the use of a dry scrubber combined with advanced baghouse for $SO_2$ and particulate matter emissions.

New air emission sources to be installed with the Cogeneration Project include the following primary and auxiliary emission units:

1. Two (2) gas-fired combustion gas turbine generators, each with a heat input rating of 637 MMBtu/hr;
2. Two (2) gas-fired HRSGs, each with duct burners with a heat input rating of approximately 434 MMBtu/hr;
3. One (1) auxiliary package boiler, natural gas fired with a heat input rating of approximately 140 MMBtu/hr;
4. Two (2) natural gas-fired dew point heaters, each with a heat input rating of 3.0 MMBtu/hr;
5. One (1) diesel-fired emergency fire pump engine, rated at 55 kW;

6. Two (2) lime storage silos and associated material handling systems;
7. One (1) diesel storage tank to supply fuel to the emergency fire pump engine; and
8. Paved haul roads for truck traffic (material receipts and waste deliveries).

The existing sources to be included with the Cogeneration Project include the following

1. Riley Boiler R2
2. Erie City Boiler T1
3. Erie City Boiler T2

These existing three (3) boilers will only operate on a limited basis in the future as needed to meet plant steam demands, and the remaining three (3) existing boilers (Boiler No. 1, Boiler No. 2 and Boiler R1) will be permanently shut down as part of this project, There will be a transition period to facilitate the initial startup and final commissioning phase of both of the new Cogeneration units, which is expected to occur over approximately ninety (90) days. As each train comes on line, it will provide electricity and steam and the existing boilers will be systematically shut down. Some existing infrastructure may be used to support the Project, but there will be no other associated emissions increases from existing units that will occur as a result of this project.

**Installation Emission Unit Summary**:

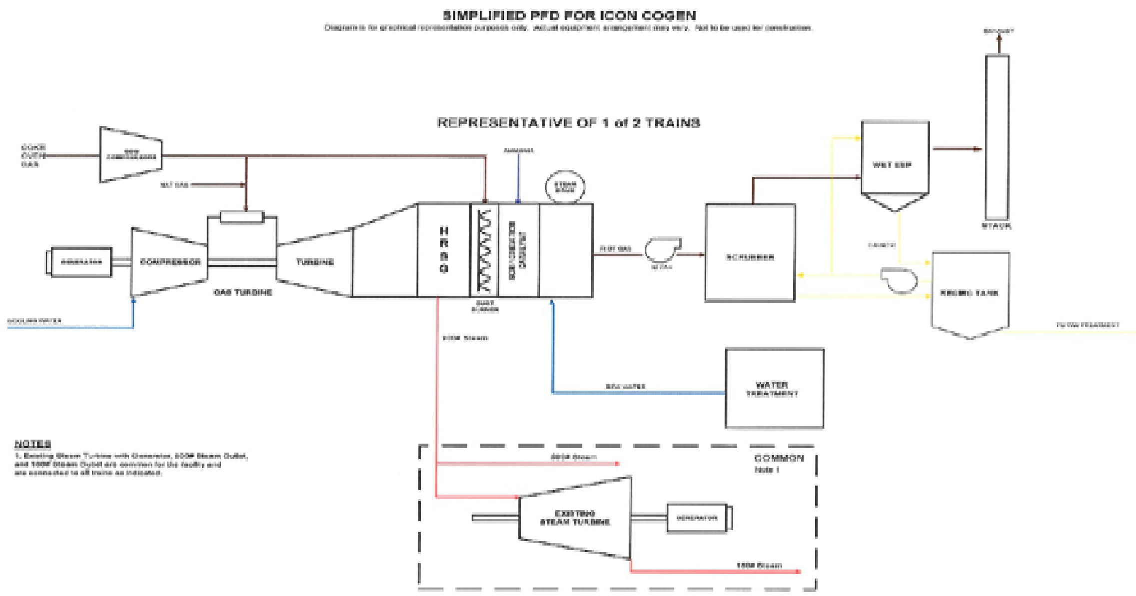
| I.D. | SOURCE DESCRIPTION | CONTROL DEVICE(S) | MAXIMUM CAPACITY | FUEL/RAW MATERIAL | STACK I.D. |
|---|---|---|---|---|---|
| COGEN 1 | Combustion Turbine and HRSG in Combined Cycle Mode | SCR, Wet Scrubber; Oxidation Catalyst; Wet ESP | 47 MW/hr | Coke Oven Gas; Natural Gas COG/NG | COGEN 1 |
| COGEN 2 | Combustion Turbine and HRSG Unit in Combined Cycle Mode | SCR, Wet Scrubber; Oxidation Catalyst; Wet ESP | 47 MW/hr | Coke Oven Gas; Natural Gas COG/NG | COGEN 2 |
| EFP | Emergency Fire Pump | None | 55kW | Diesel | FPUMP |
| HTR 1 | Dew Point Heater 1 | Low-$NO_X$ Burner | 3MMBtu/hr | Natural Gas | DPHTR-1 |
| HTR 2 | Dew Point Heater 1 | Low-$NO_X$ Burner | 3MMBtu/hr | Natural Gas | DPHTR-2 |
| B001 | Auxiliary Boiler | Low-$NO_X$ Burner with FGR | 140 MMBtu/hr | Natural gas | AUXBLR |
| B006 | Existing R2 Boiler (Riley Stoker) | None | 229 MMBtu/hr | Coke Oven Gas | S028 |
| B007 | Existing T1 Boiler (Erie City Zurn) | None | 156 MMBtu/hr | Coke Ove Gas & Natural Gas | S030 |
| B008 | Existing T2 Boiler (Erie City Zurn) | None | 156 MMBtu/hr | Coke Ove Gas & Natural Gas | S031. |
| E004 | Hydrated Lime Storage Silo | Bin Vent Filter | 37.5 tons | Lime | NA |
| E005 | Waste Lime Storage Silo | Bin Vent Filter | 37.5 tons | Lime | NA |
| E006 | Hydrated Lime Day Bins (2 bins) | Bin Vent Filter | 3 tons (each) | Lime | NA |

| I.D. | SOURCE DESCRIPTION | CONTROL DEVICE(S) | MAXIMUM CAPACITY | FUEL/RAW MATERIAL | STACK I.D. |
|---|---|---|---|---|---|
| F001 | Paved Road | Wet Suppression; Chemical dust suppressants | 1.33 miles (Lime); 1.96 miles ($NH_3$) | - | - |
| T001 | Storage Tank | None | 200 gal | No. 2 Fuel Oil | NA |

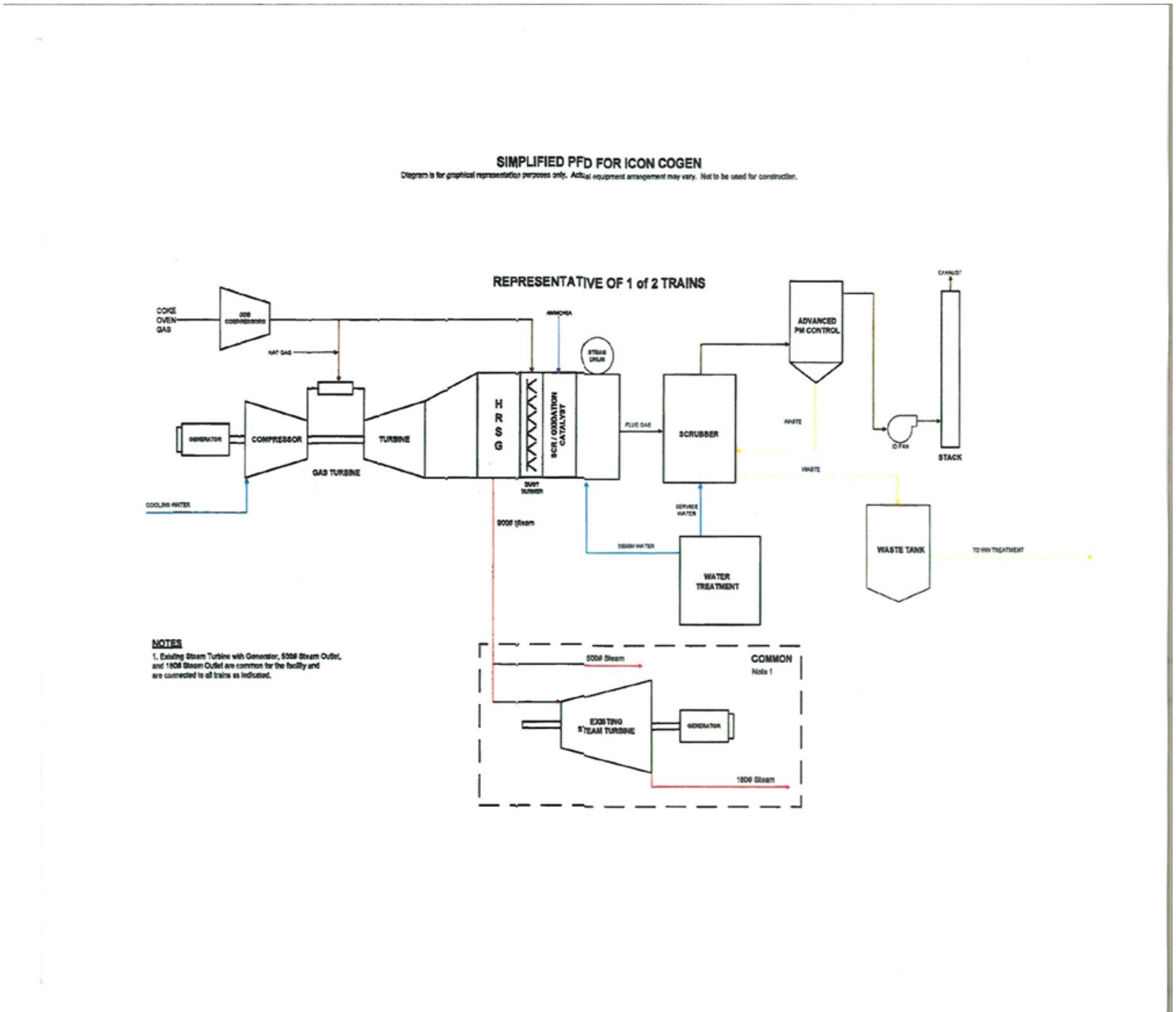
E004-E006 are part of the Alternate Control Scenario IP #0052-I019, Condition VI.A & B

## COGENERATION PROCESS FLOW DIAGRAM

### *Flow diagram with Wet Scrubber & Wet ESP for $SO_2$ & PM Control*



***Flow diagram with Alternate Control- Dry Scrubber & Baghouse for $SO_2$ & PM Control***



## PERMIT APPLICATION COMPONENTS

1. Installation Permit Application for the Proposed Cogeneration Project, prepared for U. S. Steel Corporation by Trinity Consultants, May 2, 2019.
2. Updated Installation Permit Application, June 20, 2019. It includes an updated turbine and HRSG units, from three (3) turbine trains to two (2) trains and 3 HRSG Units to two (2) units
3. Updated emissions spreadsheet, August 5, 2019 with updated turbines & HRSG manufacturers guarantee emissions;
4. Updated emissions spreadsheet, September 27, 2019 with HAPs emissions summary and updated auxiliary boiler capacity from 99 MMBtu/hr to 140 MMBtu/hr with annual capacity factor. It also includes updated BACT analysis and future emissions summary.
5. Installation Permit Application, October 11, 2019: Addendum to the application; including an alternative control scenario in which particulate matter (PM) and sulfur dioxide ($SO_2$) emissions controls for the cogeneration units include scrubber and wet electrostatic precipitator (ESP)
6. Updated Emissions Spreadsheet, October 29, 2019; Revised PSD/NNSR Analysis to show the two (2) step approach.

## 1.0 PROCESS DESCRIPTIONS AND EMISSION CONTROLS:

### 1.1 COGENERATION UNITS

The cogeneration project will provide a nominal hourly power generating capacity of approximately 94 MW (nominal, 50°F), and will consist of the installation of two (2) General Electric Frame 6B combustion turbines and two (2) Heat Recovery Steam Generation (HRSGs) that will provide steam to drive a single steam turbine (existing). The project will supply electrical power and steam to industrial processes across the Mon Valley Works complex. Each HRSG will be equipped with duct burners which may be utilized at times of peak power demands to supplement power output by supplementing the heat from the combustion turbines. The combustion turbines will be fired primarily with COG (or a blend of COG and natural gas) but will be capable of firing on 100% natural gas. The duct burners will be fired with COG only. As the project design includes some inherent redundancy, and to account for required maintenance outages, each train is expected to operate less than 8,760 hours per year.

Emissions from each train will be routed through a series of air pollution control devices, including SCR for $NO_X$ reduction, oxidation catalyst for VOC/CO reduction, wet scrubber for $SO_2$ control, and finally a wet ESP for removal of particulate matter. An alternate equivalent control scenario involves use of dry scrubbing and an advanced baghouse for $SO_2$ and particulate matter emissions.

The planned start-up and shutdown events from each train per year is estimated to be approximately 10. Emissions from each cogeneration unit is shown in table 1.1. Startup/Shutdown emissions from each cogeneration unit is shown in Table 1.1a.

**TABLE 1.1**
**Cogeneration Unit Emission Limitations per unit**

| POLLUTANT** | HOURLY EMISSION LIMIT (lb/hr) | ANNUAL EMISSION LIMIT (tons/year)* |
|---|---|---|
| Particulate Matter | 7.90 | 4.69 |
| $PM_{10}$ | 7.90 | 18.40 |
| $PM_{2.5}$ | 7.90 | 18.40 |
| Nitrogen Oxide | 25.94 | 94.66 |
| Carbon Monoxide | 5.51 | 19.33 |
| Sulfur Dioxide | 24.71 | 87.11 |
| Volatile Organic Compound | 5.89 | 15.51 |
| Ammonia | 2.56 | 9.26 |
| Lead | 0.00073 | 0.0031 |

*A year is defined as any consecutive 12-month period.
** Emissions are based on manufacturer's data for PM, $PM_{10}$, $PM_{2.5}$, $NO_X$, CO, $SO_2$, VOC and ammonia.

**TABLE 1.1a:**
**Cogeneration Unit Startup/Shutdown Emission Limitations**

| Event | NOx (lb/event) | CO (lbs/event) | $CO_2$ (lbs/event) | UHC (as $CH_4$) (lbs/event) | GHG ($CO_2$+UHC) (lbs/event) |
|---|---|---|---|---|---|
| Startup | 99.4 | 344.1 | 12,334 | 194.5 | 12,529 |
| Shutdown | 81.5 | 210.8 | 11,227 | 116.3 | 11,343 |
| | | | | | |
| **Event** | **tpy (per unit)** | **tpy (per unit)** | **tpy (per unit)** | **tpy (per unit)** | **tpy (per unit)** |
| Startup | 0.5 | 1.7 | 61.7 | 1.0 | 62.5 |
| Shutdown | 0.4 | 1.1 | 56.1 | 0.6 | 56.7 |

## 1.2 AUXILIARY PACKAGE BOILER

The scope of the proposed project will include a natural gas fired package boiler rated at 140 MMBtu/hr for auxiliary steam production. The boiler will be equipped with low-$NO_X$ burners and flue gas recirculation (FGR) and will be fired exclusively with natural gas. As this unit will be operated only on a limited basis to supplement plant steam when needed, it is expected to operate at annual capacity factor of 10%. The auxiliary boiler emissions are shown in table 1.2 and the ton/yr limit is based on 10% annual capacity factor.

**TABLE 1.2**
**Auxiliary Boiler Emission Limitations**

| POLLUTANT** | **HOURLY EMISSION LIMIT (lb/hr)** | **ANNUAL** EMISSION LIMIT **(tons/year)*** |
|---|---|---|
| Particulate Matter (filterable) | 0.30 | 0.13 |
| $PM_{10}/PM_{2.5}$ | 1.18 | 0.52 |
| Nitrogen Oxides ($NO_X$) | 1.54 | 0.67 |
| Sulfur Oxides ($SO_X$) | 0.09 | 0.04 |
| Carbon Monoxide (CO) | 5.18 | 2.27 |
| Volatile Organic Compounds (VOCs) | 0.70 | 0.31 |

*A year is defined as any consecutive 12-month period.
**$NO_X$ and CO emissions are based on manufacture's data

## 1.3 DIESEL EMERGENCY FIRE PUMP ENGINE & STORAGE TANK

The cogeneration project will include a small 55kW (75-hp) diesel-fired emergency fire pump engine. This engine is expected to meet EPA's Tier 3 engine standards and will have a small dedicated fuel storage tank associated with it (~200 gallons)

**TABLE 1.3**
**Fire Pump Engine Emission Limitations**

| **POLLUTANT** | **HOURLY EMISSION LIMIT (lb/hr)** | **ANNUAL** EMISSION LIMIT **(tons/year)*** |
|---|---|---|
| Particulate Matter ** | 0.035 | 0.002 |
| Nitrogen Oxides ($NO_X$) | 0.51 | 0.03 |
| Sulfur Oxides ($SO_X$) | 0.17 | 0.01 |
| Carbon Monoxide (CO) | 0.15 | 0.01 |
| Volatile Organic Compounds (VOCs) | 0.05 | 0.002 |

*A year is defined as any consecutive 12-month period.
**Emissions are for both filterable and condensable. Filterable PM is based on manufacture's data and condensable PM is AP-42, Table 3.4-2

## 1.4 MATERIAL HANDLING (Alternate Control Scenario)

If the alternate control scenario is selected, the Cogeneration Project will include equipment for storing and handling of lime for injection into the circulating dry scrubber as well as storage of waste lime. The emissions sources will include two (2) silos; one for storage of purchased lime and one for storage of waste lime. These silos will be equipped with high-efficiency bin vent filters for control of particulate matter during pneumatic transfer operations. There will be several smaller day bins installed as part of the material handling system which will be vented to the proposed Cogeneration Unit baghouses.

## 1.5 DEW POINT HEATERS

The fuel delivery system for the Cogeneration Units will be equipped with two (2) small natural gas-fired dew point heaters, each rated at 3.0 MMBtu/hr. These heaters will serve to prevent the formation of hydrates in the fuel lines feeding the combustion units.

**TABLE 1.5**
**Dew Point Heaters Emission Limitations**

| POLLUTANT** | HOURLY EMISSION LIMIT Per Heater (lb/hr) | ANNUAL EMISSION LIMIT Per Heater (tons/year)* |
|---|---|---|
| Particulate Matter | 0.01 | 0.06 |
| Nitrogen Oxides ($NO_X$) | 0.10 | 0.43 |
| Sulfur Oxides ($SO_X$) | 0.002 | 0.01 |
| Carbon Monoxide (CO) | 0.11 | 0.49 |
| Volatile Organic Compounds (VOCs) | 0.01 | 0.04 |

*A year is defined as any consecutive 12-month period.
**Emissions are based on manufacture's data.

## 1.6 HAUL ROADS (ASSOCIATED EMISSIONS)

There will be new truck traffic at the facility as a result of the proposed project. Deliveries of anhydrous ammonia into the facility will be expected. If the alternate control scenario is selected, there will also be deliveries of lime into the facility as well as shipments of waste lime out of the facility. All new truck traffic will occur on paved roadways.

## 1.7 EXISTING BOILERS (ASSOCIATED EMISSIONS)

As previously noted, the Cogeneration Units will provide steam to the plant, and as a result three (3) existing boilers (Boiler #1, Boiler #2, and Boiler R-1) will no longer be needed. These boilers will be permanently removed from service following final commissioning of both of the Cogeneration Units. The remaining three boilers (Boiler R-2, Boiler T-1, and Boiler T- 2) will remain in operation on a limited basis only as needed to meet plant steam demands.

**TABLE 1.7: Boiler R2 Emission Limitations**

| POLLUTANT | HOURLY EMISSION LIMIT (lb/hr) | ANNUAL EMISSION LIMIT (tons/year)* |
|---|---|---|
| Particulate Matter | 1.83 | 1.10 |
| $PM_{10}$(total) | 3.78 | 2.27 |
| $PM_{2.5}$(total) | 3.3 | 1.97 |
| Nitrogen Oxides ($NO_X$) | 47.35 | 28.41 |
| Sulfur Oxides ($SO_X$) | 33.68 | 20.21 |
| Carbon Monoxide (CO) | 45.12 | 27.07 |
| Volatile Organic Compounds (VOCs) | 0.03 | 0.02 |

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

**TABLE 1.7a: Boiler T1 & T2 Emission Limitations**

| POLLUTANT | HOURLY EMISSION LIMIT Per Boiler (lb/hr) | ANNUAL EMISSION LIMIT Per Boiler (tons/year)* |
|---|---|---|
| Particulate Matter | 0.90 | 1.0 |
| $PM_{10}$(total) | 2.14 | 2.35 |
| $PM_{2.5}$(total) | 2.21 | 2.44 |
| Nitrogen Oxides ($NO_X$) | 31.03 | 34.1 |
| Sulfur Oxides ($SO_X$) | 18.21 | 20.03 |
| Carbon Monoxide (CO) | 7.88 | 8.7 |
| Volatile Organic Compounds (VOCs) | 0.21 | 0.2 |

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

## 2.0 PREVENTION OF SIGNIFICANT DETERIORATION AND NON-ATTAINMENT NEW SOURCE REVIEW APPLICABILITY ANALYSIS

### 2.1 Regulatory Background

Allegheny County is designated as attaining the National Ambient Air Quality Standards (NAAQS) for $PM_{10}$, CO and $NO_2$ and non-attaining for $SO_2$, $PM_{2.5}$ and ozone. The pollutant $SO_2$ is considered a precursor of $PM_{2.5}$ and is therefore also likely to be treated as a non-attaining pollutant under forthcoming $PM_{2.5}$ regulations. Similarly, VOC is a precursor for ozone. $NO_x$ is considered a precursor for both $PM_{2.5}$ and ozone. Both VOC and $NO_x$ are likely to be treated as non-attainment pollutants for purposes of major new source review.

The Prevention of Significant Deterioration (PSD) regulations apply to new major sources and major modifications located in areas that are attaining the NAAQS. The PSD requirements as promulgated in 40

CFR §52.21 have been adopted by the Department in their entirety per §2102.07.a. Existing potential emissions from this facility exceed 100 tons per year for at least one pollutant. Therefore, the facility is a major source. For the Cogeneration Project to be a major modification, that is, for it to undergo PSD review, the net change in emissions due to the Project plus other contemporaneous increases and decreases in actual emissions would have to exceed PSD significance levels for at least one pollutant. With the shutdown of Boilers 1, 2 and R1 there will be a net decrease in facility-wide emissions due to the project for attaining pollutants ($NO_2$, $PM_{10}$, lead and CO).

ACHD's Article XXI regulations adopt the Federal PSD permitting procedures from 40 CFR §52.21 and the state NNSR permitting procedures from 25 PA Code §127.203. To determine the major NSR applicability for the Cogeneration Project under these two programs, the steps outlined in the U.S. EPA's NSR Workshop Manual, pages A.46-49 were generally followed. A traditional NSR applicability analysis is based on two steps: (1) determining emissions increases from the proposed project; and if increases are greater than the corresponding SER for any pollutant (2) determining the net emissions increases from the proposed project and other contemporaneous changes at the facility. These steps are discussed in detail in the following sections.

## 2.2 Overview of Emissions Netting/Project Emissions Accounting Procedures

In assessing PSD applicability, the procedures in 40 CFR 52, §52.21 and in assessing NNSR applicability, the procedures described in PADEP's Pennsylvania Code, Subchapter E, §127.203a were followed:

Only project-related emissions are evaluated in this step; any contemporaneous increases or decreases are considered in Step 2.

1. Calculate the future allowable emissions for the new units, using potential-to-emit (PTE). For existing sources that are modified or otherwise associated with the project, use projected actual emissions (PAE). If the future emissions from the new units exceed PSD and /or NNSR significance levels, then

2. Calculate baseline actual emissions (BAE) from the highest 24-month average actuals over the last 10 years for PSD pollutants and the last 5 years for NNSR pollutants for existing units affected by the Cogeneration Project, that is, existing units that will be shut down and units whose emissions will increase or decrease. The same 24-month period must be used for all sources affected by the project (existing sources that will be modified or will see an increase associated with the project). A different baseline period can be used for different pollutants, but must include all affected sources of that pollutant, and

3. Calculate contemporaneous emission changes associated with minor source permits;

4. Subtract emissions calculated in steps 2 and 3 from those in step 1 to determine the net emissions change resulting from the Project. If the difference is less than the PSD and NNSR significance limits, the project is considered a minor modification and PSD and NNSR will not apply.

## 2.3 Calculating Future Allowable Emissions from New Equipment and Baseline Actual Emissions for Boilers R2, T1 and T2

The proposed Cogeneration Project involves the installation of new sources and the concurrent shut down of Boilers 1, 2 and R1. In addition, U.S. Steel is establishing restrictions to limit the future operation of three (3) boilers at Clairton (Boiler R-2, Boiler T-1, and Boiler T-2). Therefore, PTE from the proposed new sources, the actual emissions increases from the three (3) existing boilers that will remain, and the decreases from the shutdown of three (3) of the plant's existing boilers were used in determining the project emissions increase for comparison against the Significant Emissions Rates (SERs). As shown in Table 9 and Table 13, emissions increases associated with the project do not exceed the PSD and /or NNSR SER for any pollutant.

### 2.3.1 Future Allowable Emissions

The following new equipment will be installed:

Cogeneration Units, which includes the following emissions sources

Two (2) Combustion Turbines
Two (2) Heat Recovering Steam Generation (HRSG)
Emergency Fire Pump
Two (2) Dew point heaters
Auxiliary Boiler
Material Handling
Storage Tank

Some of the future allowable emissions have been provided by the manufacturer. However, AP-42 emissions factors and USS engineering judgment were used where guarantees could not be provided. Potential short-term emissions are based on the maximum worst case scenarios (i.e., one train operating at 100% CTG load and full duct firing) from the full range of fuel scenarios and ambient temperatures. However, it is not possible for both units to operate at this worst-case scenario concurrently for extended periods of time. Therefore, maximum potential long-term emissions for each pollutant are based on the following criteria:

- Worst-case annual operating schedule (i.e., slightly less than full year operation); AND
- Maximum hourly emission rate of two units operating at average ambient conditions; OR
- One unit operating at its worst-case load at average ambient conditions.

As provided in the permit application, these maximum capacities are presented in Table 1:

**Table 1**
**Maximum Capacities for Cogeneration Units**

| | |
|---|---|
| No. of Turbines | 2 |
| No. of HGRS Duct Burner | 2 |
| Duct Firing | Normal |
| Load | 100% |
| Ambient Temperature | Avg (30ºF) |
| Fuel | COG |
| Gas Turbine Generator Heat Input (MMBtu/hr) | 637 |
| HRGS Duct Burner Heat Input (MMBtu/hr) | 437 |
| Auxiliary Boiler (MMBtu/hr) | 140 |
| Fire Pump Engine (kW) | 55 |

### 2.3.2 Existing Equipment Associated with the Cogeneration Project

**Table 2**

| | |
|---|---|
| No. of Boilers | 3 |
| Boiler R2 Capacity (MMBtu/hr) | 229 |
| Boiler T1 Capacity (MMBtu/hr) | 156 |
| Boiler T1 Capacity (MMBtu/hr) | 156 |
| | |
| Max. Annual Hours of Operation at Full Load (hr/yr): | |
| Boiler R2 | 1,200 |
| Boiler T1 | 2,200 |
| Boiler T2 | 2,200 |

### 2.3.3 Baseline Actual Emissions

The following existing equipment will be shutdown:

**Table 3**

| | |
|---|---|
| No. of Boilers | 3 |
| Boiler 1 Capacity (MMBtu/hr) | 760 |
| Boiler 2 Capacity (MMBtu/hr) | 481 |
| Boiler R1 Capacity (MMBtu/hr) | 229 |

The information contained in Tables 1, 2 and 3 were used to calculate pollutant emissions for the project emissions increase analysis. Emission reductions will be realized from the shutdown of Boilers 1, 2 and R1 and emission increases will result from the operation of the proposed new Cogeneration units, Auxiliary boiler, Dew Point Heaters and emission associated with the small increases in material handling.

**Table 4**
**Emissions from the Cogeneration Operation**

| PROCESS | $NO_X$ tons/yr | $SO_2$ tons/yr | VOC tons/yr | PM tons/yr | $PM_{10}$ tons/yr | $PM_{2.5}$ tons/yr | CO tons/yr | $NH_3$ tons/yr | $CO_2e$ tons/yr |
|---|---|---|---|---|---|---|---|---|---|
| Cogen Unit 1 | 94.70 | 87.10 | 15.50 | 4.70 | 18.40 | 18.40 | 19.30 | 9.30 | 432,048 |
| Cogen Unit 2 | 94.70 | 87.10 | 15.50 | 4.70 | 18.40 | 18.40 | 19.30 | 9.30 | 432,048 |
| Aux Boiler | 0.67 | 0.04 | 0.30 | 0.10 | 0.50 | 0.50 | 2.30 | 0.00 | 8,257 |
| Dew Heater 1 | 0.40 | 0.0066 | 0.039 | 0.10 | 0.10 | 0.10 | 0.50 | 0.00 | 1,769.50 |
| Dew Heater 2 | 0.40 | 0.0066 | 0.039 | 0.10 | 0.10 | 0.10 | 0.50 | 0.00 | 1,769.50 |
| Fire Pump Engine | 0.03 | 0.0087 | 0.0024 | 0.0015 | 0.0017 | 0.0017 | 0.01 | 0.00 | 4.90 |
| Hydrated Lime Silo | 0.00 | 0.00 | 0.00 | 0.04 | 0.04 | 0.04 | 0.00 | 0.00 | 0.00 |
| Wasted Lime Silo | 0.00 | 0.00 | 0.00 | 0.04 | 0.04 | 0.04 | 0.00 | 0.00 | 0.00 |
| Paved Roads (Hydrated Lime) | 0.00 | 0.00 | 0.00 | 0.033 | 0.0067 | 0.0016 | 0.00 | 0.00 | 0.00 |
| Paved Roads (CDS Material) | 0.00 | 0.00 | 0.00 | 0.050 | 0.010 | 0.0025 | 0.00 | 0.00 | 0.00 |
| Paved Roads ($NH_3$) | 0.00 | 0.00 | 0.00 | 0.0041 | 0.0008 | 0.0002 | 0.00 | 0.00 | 0.00 |
| Diesel Tank | 0.00 | 0.00 | 0.000003 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Boiler R2 | 28.40 | 20.20 | 0.018 | 1.10 | 2.30 | 2.0 | 27.10 | 0.00 | 14,204 |
| Boiler T1 | 34.10 | 20.0 | 0.20 | 1.0 | 2.40 | 2.40 | 8.70 | 0.00 | 12,417.7 |
| Boiler T2 | 34.10 | 20.0 | 0.20 | 1.0 | 2.40 | 2.40 | 8.70 | 0.00 | 12,417.7 |
| | | | | | | | | | |
| **Total** | **287.55** | **234.56** | **31.87** | **12.89** | **44.50** | **44.35** | **86.32** | **18.97** | **926,993** |

**Table 5**
**Baseline Actual Emissions for Boilers 1, 2 and R1**

| PROCESS | $NO_X$ tons/yr | $SO_2$ tons/yr | VOC tons/yr | PM tons/yr | $PM_{10}$ tons/yr | $PM_{2.5}$ tons/yr | CO tons/yr | $NH_3$ tons/yr | $CO_2e$ tons/yr |
|---|---|---|---|---|---|---|---|---|---|
| Boiler 1 | 644.90 | 229.54 | 2.03 | 21.07 | 29.78 | 29.78 | 83.55 | 0.99 | 157,905 |
| Boiler 2 | 211.50 | 125.28 | 0.41 | 9.17 | 13.48 | 13.48 | 44.74 | 0.65 | 97,232 |
| Boiler R1 | 15.90 | 8.29 | 0.01 | 0.76 | 0.16 | 0.16 | 2.08 | 0.02 | 4,087 |
| | | | | | | | | | |
| **Total** | **872.3** | **363.11** | **2.45** | **31.0** | **43.42** | **43.42** | **130.37** | **1.66** | **259,224** |

See Table 2.7.1 for the baseline 24-month period used

**Baseline Actual Emissions for Boilers R2, T1 and T2**

| PROCESS | $NO_X$ tons/yr | $SO_2$ tons/yr | VOC tons/yr | PM tons/yr | $PM_{10}$ tons/yr | $PM_{2.5}$ tons/yr | CO tons/yr | $NH_3$ tons/yr | $CO_2e$ tons/yr |
|---|---|---|---|---|---|---|---|---|---|
| Boiler R2 | 17.05 | 13.88 | 0.01 | 0.96 | 0.74 | 0.74 | 2.02 | 0.02 | 5,013 |
| Boiler T1 | 23.63 | 19.84 | 0.01 | 1.20 | 0.72 | 0.72 | 3.89 | 0.03 | 9,298 |
| Boiler T2 | 18.26 | 18.22 | 0.11 | 1.20 | 0.73 | 0.73 | 3.89 | 0.03 | 9,298 |
| | | | | | | | | | |
| **Total** | **58.94** | **51.94** | **0.13** | **3.36** | **2.19** | **2.19** | **9.80** | **0.08** | **23,609** |

See Table 2.7.1 for the baseline 24-month period used

**TABLE 6**
**PSD/NSR Pollutant**

| Pollutant[1] | PSD/NNSR | Significant Emission Rate (tpy) |
|---|---|---|
| PM (filt.) | PSD | 25 |
| $PM_{10}$ (filt. + cond.) | PSD | 15 |
| $PM_{2.5}$ (filt. + cond.) | NNSR | 10 |
| Lead | PSD | 1 |
| $SO_2$ | NNSR | 40 |
| $NO_X/NO_2$ | NNSR (Ozone & $PM_{2.5}$ precursor) PSD | 40 |
| CO | PSD | 100 |
| VOC | NNSR (Ozone & $PM_{2.5}$ precursor) | 40 |
| Ammonia | NNSR ($PM_{2.5}$ precursor) | 40 |
| $CO_2e$ | PSD | 75,000 |

[1]PSD also has established SERs for hydrogen sulfide, total reduced sulfur, and sulfuric acid mist, which could be emitted from the sources being permitted in this action. If present at all, these compounds are expected to be at concentrations below method detection limits. Given the air pollution control devices and strategies being employed, these compounds would be expected to show up in the "back-half" of the particulate matter sampling train. The condensable particulate matter estimates for the proposed sources account for the possible presence of these compounds. The proposed project is not expected to increase emissions of any other NSR regulated pollutants (e.g., CFCs).

## 2.4 Project Emission Summary- PSD Pollutant

**Future Emissions (tpy)**

**TABLE 7**

| Emission Unit/Pollutant[1,6] | Step 1 - Future Emissions (tpy)[2] | | | | | |
|---|---|---|---|---|---|---|
| | PM (filt.) | $PM_{10}$ (filt. + cond.) | Lead | $NO_2$ | CO | $CO_2e$ |
| Cogen Unit 1 (Turbine + Duct Firing) | 4.7 | 18.4 | 3.1E-03 | 94.7 | 19.3 | 432,048.0 |
| Cogen Unit 2 (Turbine + Duct Firing) | 4.7 | 18.4 | 3.1E-03 | 94.7 | 19.3 | 432,048.0 |
| Diesel Emergency Fire Pump | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 4.9 |
| Package Boiler | 0.1 | 0.5 | 3.4E-05 | 0.7 | 2.3 | 8,257.4 |
| Dew Point Heater 1 | 0.1 | 0.1 | 7.3E-06 | 0.4 | 0.5 | 1,769.5 |
| Dew Point Heater 2 | 0.1 | 0.1 | 7.3E-06 | 0.4 | 0.5 | 1,769.5 |
| Hydrated Lime Bin Vent | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Waste Lime Silo Bin Vent | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Hydrated Lime | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Baghouse/CDS Materials | 0.1 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Anhydrous NH3 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Fire Pump Diesel Tank | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Boiler R-2 | 1.1 | 2.3 | 1.2E-04 | 28.4 | 27.1 | 14,204.1 |
| Boiler T-1 | 1.0 | 2.4 | 1.3E-04 | 34.1 | 8.7 | 18,445.9 |
| Boiler T-2 | 1.0 | 2.4 | 1.3E-04 | 34.1 | 8.7 | 18,445.9 |
| Boiler 1 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Boiler 2 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Boiler R-1 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| **Total** | **12.9** | **44.5** | **6.6E-03** | **287.6** | **86.3** | **926,993.1** |

[2]Future emissions from new units is potential to emit. Future emissions from associated units is projected actuals which account for the maximum annual rate projected in the next 5 years following resumption of regular operation after the project.

**Baseline Actual Emissions**

**TABLE 8**

| Emission Unit/Pollutant[1,6] | Step 2 - Baseline Actual Emissions (tpy)[3] | | | | | |
|---|---|---|---|---|---|---|
| | PM (filt.) | $PM_{10}$ (filt. + cond.) | Lead | $NO_2$ | CO | $CO_2e$ |
| Cogen Unit 1 (Turbine + Duct Firing) | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Cogen Unit 2 (Turbine + Duct Firing) | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Diesel Emergency Fire Pump | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Package Boiler | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Dew Point Heater 1 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Dew Point Heater 2 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Hydrated Lime Bin Vent | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Waste Lime Silo Bin Vent | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Hydrated Lime | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Baghouse/CDS Materials | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Anhydrous NH3 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Fire Pump Diesel Tank | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.0 |
| Boiler R-2 | 1.0 | 0.7 | 0.0E+00 | 17.1 | 2.0 | 5,013.1 |
| Boiler T-1 | 1.2 | 0.7 | 0.0E+00 | 23.6 | 3.9 | 9,297.7 |
| Boiler T-2 | 1.2 | 0.7 | 0.0E+00 | 18.3 | 3.9 | 9,297.7 |
| Boiler 1 | 21.1 | 29.8 | 2.2E-04 | 644.9 | 83.5 | 157,905.1 |
| Boiler 2 | 9.2 | 13.5 | 1.3E-04 | 211.5 | 44.7 | 97,232.4 |
| Boiler R-1 | 0.8 | 0.2 | 0.0E+00 | 15.9 | 2.1 | 4,086.9 |
| **Total** | **34.4** | **45.6** | **3.5E-04** | **931.3** | **140.2** | **282,833.0** |

[3]Baseline emissions are the highest 2-year average actual emissions from the last 10 years as reported by U. S. Steel as part of annual emissions inventories (see section 2.7.1 below for the baseline 24 month period used). Procedures were followed specific to non-EGU provisions as the proposed system, and the associated units, do not meet the definition of an electric generating unit (EGU)

**TABLE 9**

| Emission Unit/Pollutant[1,6] | Step 1 - Project Emissions Increase (tpy)[5] | | | | | |
|---|---|---|---|---|---|---|
| | PM (filt.) | $PM_{10}$ (filt. + cond.) | Lead | $NO_2$ | CO | $CO_2e$ |
| Cogen Unit 1 (Turbine + Duct Firing) | 4.7 | 18.4 | 3.1E-03 | 94.7 | 19.3 | 432,048.03 |
| Cogen Unit 2 (Turbine + Duct Firing) | 4.7 | 18.4 | 3.1E-03 | 94.7 | 19.3 | 432,048.03 |
| Diesel Emergency Fire Pump | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 4.87 |
| Package Boiler | 0.1 | 0.5 | 3.4E-05 | 0.7 | 2.3 | 8,257.44 |
| Dew Point Heater 1 | 0.1 | 0.1 | 7.3E-06 | 0.4 | 0.5 | 1,769.45 |
| Dew Point Heater 2 | 0.1 | 0.1 | 7.3E-06 | 0.4 | 0.5 | 1,769.45 |
| Hydrated Lime Bin Vent | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.00 |
| Waste Lime Silo Bin Vent | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.00 |
| Paved Roads - Hydrated Lime | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.00 |
| Paved Roads - Baghouse/CDS Materials | 0.1 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.00 |
| Paved Roads - Anhydrous NH3 | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.00 |
| Fire Pump Diesel Tank | 0.0 | 0.0 | 0.0E+00 | 0.0 | 0.0 | 0.00 |
| Boiler R-2 | 0.1 | 1.5 | 1.2E-04 | 11.4 | 25.0 | 9,191.02 |
| Boiler T-1 | -0.2 | 1.6 | 1.3E-04 | 10.5 | 4.8 | 9,148.15 |
| Boiler T-2 | -0.2 | 1.6 | 1.3E-04 | 15.9 | 4.8 | 9,148.15 |
| Boiler 1 | -21.1 | -29.8 | -2.2E-04 | -644.9 | -83.5 | -157,905.14 |
| Boiler 2 | -9.2 | -13.5 | -1.3E-04 | -211.5 | -44.7 | -97,232.36 |
| Boiler R-1 | -0.8 | -0.2 | 0.0E+00 | -15.9 | -2.1 | -4,086.95 |
| **Total** | **-21.5** | **-1.1** | **6.3E-03** | **-643.7** | **-53.8** | **644,160.13** |
| **PSD SER** | 25 | 15 | 1 | 40 | 100 | 75,000 |
| **Increase > SER?[4]** | NO | NO | NO | NO | NO | YES |

[4]Per 40 CFR §52.21(b)(49)(iv), as an existing major stationary source, GHGs (CO2e) is only subject to PSD if there is an emission increase of another regulated NSR pollutant AND an emission increase of 75,000 tpy CO2e or more. Since there is no emissions increase of a regulated NSR pollutant, PSD is not triggered for CO2e.

[5]In accordance with EPA's latest Project Emissions Accounting guidance for PSD pollutants, this step includes both increases and decreases associated with the project.

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### 2.5 Project Emission Summary- Nonattainment Pollutant

The cogeneration netting analysis for the Non-attainment pollutant is shown in the tables below. Tables 10 and 11 show step1 of the analysis and Tables 12 and 13 show step 2.

**TABLE 10**
**Nonattainment Pollutants (Step 1)**

| | Future Emissions (tpy)[1] | | | | |
|---|---|---|---|---|---|
| **Emission Unit/Pollutant[4]** | **$PM_{2.5}$ (filt. + cond.)** | **$SO_2$** | **$NO_x$** | **VOC** | **Ammonia** |
| Cogen Unit 1 (Turbine + Duct Firing) | 18.4 | 87.1 | 94.7 | 15.5 | 9.3 |
| Cogen Unit 2 (Turbine + Duct Firing) | 18.4 | 87.1 | 94.7 | 15.5 | 9.3 |
| Diesel Emergency Fire Pump | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Package Boiler | 0.5 | 0.0 | 0.7 | 0.3 | 0.0 |
| Dew Point Heater 1 | 0.1 | 0.0 | 0.4 | 0.0 | 0.0 |
| Dew Point Heater 2 | 0.1 | 0.0 | 0.4 | 0.0 | 0.0 |
| Hydrated Lime Bin Vent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Waste Lime Silo Bin Vent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Hydrated Lime | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Baghouse/CDS Materials | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Anhydrous NH3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fire Pump Diesel Tank | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Boiler R-2 | 2.0 | 20.2 | 28.4 | 0.0 | 0.0 |
| Boiler T-1 | 2.4 | 20.0 | 34.1 | 0.2 | 0.2 |
| Boiler T-2 | 2.4 | 20.0 | 34.1 | 0.2 | 0.2 |
| **Total** | **44.4** | **234.6** | **287.6** | **31.9** | **19.0** |

[1]Future emissions from new units is potential to emit. Future emissions from associated units is projected actuals which account for the maximum annual rate projected in the next 5 years following resumption of regular operation after the project.

**TABLE 11**
**Nonattainment Pollutants (Step 1)**

| | Baseline Actual Emissions (tpy)[2] | | | | |
|---|---|---|---|---|---|
| **Emission Unit/Pollutant[4]** | **$PM_{2.5}$ (filt. + cond.)** | **$SO_2$** | **$NO_x$** | **VOC** | **Ammonia** |
| Cogen Unit 1 (Turbine + Duct Firing) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cogen Unit 2 (Turbine + Duct Firing) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Diesel Emergency Fire Pump | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Package Boiler | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dew Point Heater 1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dew Point Heater 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydrated Lime Bin Vent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Waste Lime Silo Bin Vent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Hydrated Lime | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Baghouse/CDS Materials | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Anhydrous NH3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fire Pump Diesel Tank | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Boiler R-2 | 0.7 | 13.9 | 17.1 | 0.0 | 0.0 |
| Boiler T-1 | 0.7 | 19.8 | 23.6 | 0.0 | 0.0 |
| Boiler T-2 | 0.7 | 18.2 | 18.3 | 0.1 | 0.0 |
| **Total** | **2.2** | **51.9** | **59.0** | **0.1** | **0.1** |

[2]Baseline emissions are the highest 2-year average actual emissions from the last 5 years as reported by U. S. Steel as part of annual emissions inventories. Procedures were followed specific to non-EGU provisions as the proposed system, and the associated units, do not meet the definition of an electric generating unit (EGU).



**Table 12**
**Nonattainment Pollutants (Step 2)**

| **Pollutant** | **Contemporaneous Increases[1]** | | | **Contemporaneous Decreases[1]** | | | |
|---|---|---|---|---|---|---|---|
| | **Crude Tar Processing** | **Truck Light Oil Loading** | **Total** | **Boiler 1 Shutdown** | **Boiler 2 Shutdown** | **Boiler R-1 Shutdown** | **Total** |
| | **(tpy)** | **(tpy)** | **(tpy)** | **(tpy)** | **(tpy)** | **(tpy)** | **(tpy)** |
| $PM_{2.5}$ (filt. + cond.) | 0.0 | 0.0 | 0.0 | -29.8 | -13.5 | -0.2 | -43.4 |
| $SO_2$ | 0.0 | 0.0 | 0.0 | -229.5 | -125.3 | -8.3 | -363.1 |
| $NO_x$ | 0.0 | 0.0 | 0.0 | -644.9 | -211.5 | -15.9 | -872.3 |

[1]The contemporaneous period begins 5 years before construction on the project commences and ends the date that construction on the project is completed. Based on the application completeness determination made by ACHD on June 13, 2019, and using that date as meeting the definition of "commence", the contemporaneous period for major NNSR purposes, begins June 13, 2014 and ends upon startup of the new cogeneration units.

**TABLE 13**
**Emissions Netting Summary (Step 2)**

| | Project Increase Emissions (tpy)[3] | | | | |
|---|---|---|---|---|---|
| **Emission Unit/Pollutant[4]** | **$PM_{2.5}$ (filt. + cond.)** | **$SO_2$** | **$NO_x$** | **VOC** | **Ammonia** |
| Cogen Unit 1 (Turbine + Duct Firing) | 18.4 | 87.1 | 94.7 | 15.5 | 9.3 |
| Cogen Unit 2 (Turbine + Duct Firing) | 18.4 | 87.1 | 94.7 | 15.5 | 9.3 |
| Diesel Emergency Fire Pump | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Package Boiler | 0.5 | 0.0 | 0.7 | 0.3 | 0.0 |
| Dew Point Heater 1 | 0.1 | 0.0 | 0.4 | 0.0 | 0.0 |
| Dew Point Heater 2 | 0.1 | 0.0 | 0.4 | 0.0 | 0.0 |
| Hydrated Lime Bin Vent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Waste Lime Silo Bin Vent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Hydrated Lime | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Baghouse/CDS Materials | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads - Anhydrous NH3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fire Pump Diesel Tank | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Boiler R-2 | 1.2 | 6.3 | 11.4 | 0.0 | 0.0 |
| Boiler T-1 | 1.7 | 0.3 | 10.5 | 0.2 | 0.2 |
| Boiler T-2 | 1.7 | 1.8 | 15.9 | 0.1 | 0.2 |
| | | | | | |
| **Total (Baseline)** | **42.2** | **182.6** | **228.6** | **31.7** | **18.9** |
| | | | | | |
| **Total (Baseline + Contemporaneous) Tables 11 & 12** | **-1.3 [(42.2 + (-43.3)]** | **-180.50 [182.6 + (-363.1)]** | **-643.70 [228.6 + (-872.3)]** | **31.7** | **18.9** |
| **NNSR SER** | 10 | 40 | 40 | 40 | 40 |
| **Increase > NN SER[4]?** | NO | NO | NO | NO | NO |

[3]In accordance with ACHD's netting procedures for nonattainment pollutants, Step 1 includes only the increases associated with the project.
[4]There are no other projects or sources that must be aggregated with this project. All existing infrastructure that has air emissions and which is impacted by the project have been accounted for in this analysis. Additional infrastructure that does not have air emissions may be impacted by this project (e.g., fuel delivery systems/piping).

The following sections discuss the methodology used to assess NSR applicability. The NSR permitting program generally requires that a source obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. ACHD has incorporated by reference 40 CFR §52.21 as well as 25 Pa Code §§127.203 - 204.

## 2.6 Defining Existing versus New Emission Units

Different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by the proposed project is considered a new or existing emission unit.

40 CFR §52.21(b)(7)(i) and (ii), as well as 25 PA Code § 121.1, define new unit and existing units:

*(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first opera ted.*

*(ii) An existing emissions unit* is *any unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit*

New sources associated with the project are the combustion turbines and HRSGs as well as the package auxiliary boiler, emergency fire pump engine and associated fuel tank, the dew point heaters, and the material handling systems. Existing sources that will be impacted by the Cogeneration Project are the six boilers and certain segments of paved roadways.

## 2.7 Annual Emission Increase Calculation Methodology

As the facility is classified as an existing major source for NSR, if the Cogeneration Project were classified as a *major modification*, then the full NSR permitting requirements would apply. U. S. Steel has determined the project emissions increase in accordance with EPA guidance to determine if the proposed project is a major modification. The methodology outlined in 25 Pa Code §127.203a(a)(l)(i) was relied upon for conducting this applicability analysis for nonattainment pollutants. For PSD, the procedures of 40 CFR §52.21 have been followed.

§127.203a(a)(l)(i)(A) provides the emission increase calculation method for existing units (i.e., the boilers in this case):

(*A) For existing emissions units, an emission increase of a regulated NSR pollutant is the difference between the projected actual emissions and the previous actual emissions for each unit, as determined in paragraphs (4) and (5). When calculating an increase in emissions that results from the particular project, exclude that portion of the unit's emissions following completion of the project that existing units could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that is also unrelated to the particular project, including all increased utilization due to product demand growth as specified in paragraph (5)(i)(C).*

§127.203a(a)(l)(i)(8) provides the emission increase calculation method for new emission units (i.e., the combustion turbines, HRSGs, package boiler, emergency fire pump engine, diesel storage tank, heaters, and material handling sources in this case):

*(B) For new emissions units, the emissions increase of a regulated NSR pollutant will be the potential to emit from each new emissions unit*

*Major modification* is defined by 40 CFR §52.21(b)(2)(i) and 25 Pa Code §121 as:

*"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase ... of a regulated NSR pollutant ... and a significant net emission increase of that pollutant ...*

As the project is classified as a physical change, the project needs to be analyzed to determine if a significant emissions increase, or a significant net emissions increase will occur. The first step (Step 1) is commonly referred to as the "project emission increases" as it accounts only for emissions changes related to the proposed project itself. If the emission increases estimated per Step 1 exceed the major modification thresholds, then the applicant may move to Step 2, commonly referred to as "netting". The netting analysis includes all projects for which emission increases or decreases have occurred or will occur during a period of time contemporaneous to the project. If the resulting net emission increases exceed the major modification threshold, then NSR permitting is required. These basic procedures are the same for both PSD and NNSR

### 2.7.1 Baseline Actual Emissions (BAE)

For the purposes of NNSR, baseline actual emissions are defined in 25 Pa Code §127.203a(a)(4)(i) as follows:

*For an existing emissions unit, baseline actual emissions are the average rate, in TPY, at which the unit emitted the regulated NSR pollutant during a consecutive 24-month period selected by the owner or the operator within the 5-year period immediately prior to the date a complete plan approval application is received by the Department The Department may approve the use of a different consecutive 24-month period within the last 10 years upon a written determination that it is more representative of normal source operation*

Per §127.203a(a)(4)(i)(D), when a project involves multiple emission units, only one consecutive 24-month period may be used to determine the baseline actual emissions for all the emission units being changed. However, there are provisions to use a different consecutive 24-month period can be used for each pollutant.

U. S. Steel elected to use the 24 consecutive calendar months, as reported in annual emissions report (i.e., annual totals), in each of the selected baseline periods for simplicity and did not seek to evaluate each 24-calendar month period in the last 5 years. For the Cogeneration Project, a baseline period of 2014 and 2015 was selected for all nonattainment pollutants with the exception of $PM_{2.5}$. These two years (2014 & 2015) reflect the maximum coke production and fuel combustion rates observed in the most recent five-year period.

ACHD adopts by reference EPA's PSD program outlined in 40 CFR §52.21. For the PSD program, baseline actual emissions for an emissions unit, other than an electric utility steam generating unit, are defined in 40 CFR §52.21(b)(48)(ii)

*the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator*

Further clarification is given that only one consecutive 24-month period may be used to determine the baseline for all the emission units being changed but that a different period can be used for each regulated pollutant. U.S. Steel computed actual baseline emissions for PSD pollutants following this procedure and selected the following as baseline periods:

- PM= 2010 and 2011;
- PM10=2016 and2017;
- CO= 2012 and 2013;
- NOx = 2014 and 2015;
- GHG = 2013 and 2014; and
- Lead= 2015 and 2016.

### 2.7.2 Potential Emissions (PTE)

Potential to emit is defined by 25 Pa Code §121.1 and §2101.20 as:

*The maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and limitations on hours of operation or on the type or amount of material combusted,* *stored or processed shall be treated as part of the design if the limitation or the effect it would have on emissions is Federally enforceable or legally and practicably enforceable by an operating permit condition. The term does not include secondary emission from an offsite facility.*

Any modification to the facility that has the potential to increase emissions of any air pollutant(s) regulated under the PSD or NNSR program must be evaluated to determine if the changes are subject to PSD or NNSR. Per §2101.20, a "modification" is defined as:

*... A physical change in a source or a change in the method of operation of a source which would increase the amount of an air contaminant emitted by the source or which would result in the emission of an air contaminant not previously emitted, except that routine maintenance, repair and replacement are not considered physical changes.*

The Cogeneration Project at the Clairton Plant qualifies as a "modification" under this definition. Therefore, the proposed process changes are identified as a potential modification requiring evaluation under the NSR permitting program.

### 2.7.3 Proposed Project Emissions Increases

The following sections summarize the methods to estimate the emissions increases from the Cogeneration Project for comparison to the NSR permitting major modification thresholds. In determining the potential emissions from the new units, U.S. Steel assumed year-round operation of the cogeneration units, taking into account redundancy and required routine maintenance outages. For the purposes of the NSR analysis, annual emissions were estimated based on representative average operating conditions (e.g., load, ambient temperatures, and fuels). Potential emissions from the package boiler are limited to the 10% annual capacity factor, and potential emissions from the emergency fire pump engine were based on the assumption that the unit would operate no more than 100 hours per year, respectively.

For the three existing boilers that will remain in operation, U.S. Steel estimated their future projected emissions using emission factors derived from a statistical analysis of historical stack test data along with projected annual fuel consumption based on limited operation due to their intended function in the future (i.e., plant steam production only when needed).

### 2.7.4 Proposed Project Emissions Decreases

The sources listed below will cease operations or modify operation upon start up and commencement of normal operation of the Cogeneration Project. As such, emission decreases for this equipment will occur within the scope of the project and can be credited in the NSR applicability analysis.

- Boiler #1 - 760 MM Btu/hr (coke oven gas and/or natural gas fired)
- Boiler #2 - 481 MMBtu/hr (coke oven gas and/or natural gas fired)
- Boiler R-1- 229 MMBtu/hr (coke oven gas and/or natural gas fired)
- Boiler R2 – 229 MMBtu/hr (coke oven gas and/or natural gas fired)
- Boiler T1 – 156 MMBtu/hr (coke oven gas and/or natural gas fired)
- Boiler T2 - 156 MMBtu/hr (coke oven gas and/or natural gas fired)

The methodology used to establish baseline actual emissions for these sources is discussed in Section 2.2 above. The actual emissions used in the applicability analysis are the same actual emissions that have been reported to ACHD in the Clairton Plant's Annual Emissions Inventory Statement.

### 2.7.5 Sum of Project Emissions

The calculations in the tables above provide a detailed summary of emissions changes as a result of the project. As the sum of these changes is below the corresponding SER for all pollutants, the Cogeneration Project is not a major modification and not subject to major PSD/NNSR permitting.

U.S. Steel has identified the following contemporaneous projects at Clairton that fall within this window for $NO_X$, VOC and/or $SO_2$:

- C Battery (IP-11);
- Crude tar processing (IP-15, VOC only); and
- Truck light oil loading (IP-16, VOC only).

## 3.0 REVIEW OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

According to Article XXI, §2101.20 Definitions: "Best Available Control Technology" means an emission limitation based on the maximum degree of reduction of each air contaminant regulated by this Article, which the Department determines on a case-by-case basis to be achievable taking into account the energy, environment, and economic impacts and other costs. In no event shall application of BACT result in emissions of any air contaminant exceeding the emissions allowed under any applicable New Source Performance Standard (NSPS), any National Emission Standard for Hazardous Air Pollutants (NESHAP), or any Reasonably Available Control Technology (RACT) emission limit under this Article.

In accordance with the above BACT definition and U.S. EPA and ACHD guidance, the Installation Permit Application submitted by U. S. Steel Corporation, BACT was determined through a "top-down" assessment that started with the Lowest Achievable Emission Rate (LAER) and proceeded through consideration of progressively lesser levels of control. Separate assessments were made for each emissions unit subject to BACT, and each pollutant subject to BACT was considered separately.

Step 1 - Identify all potential control technologies
Step 2 - Determine technical feasibility (of potential technologies)
Step 3 - Rank control technologies by control effectiveness
Step 4 - Evaluate most effective controls and document results
Step 5 - Select BACT

### 3.1 $NO_X$ BACT ANALYSIS - COMBUSTION TURBINES

COG contains molecular nitrogen and ammonia. Therefore, the majority of the $NO_X$ emissions from the combustion turbines will originate as thermal $NO_X$, However, some $NO_X$ will be generated as the result of fuel-bound nitrogen oxidation. The rate of formation of thermal $NO_X$ is a function of residence time and free oxygen and is exponential with peak flame temperature. Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that most $NO_X$ emissions from the combustion turbines will originate as thermal $NO_X$ when combusting either fuel or a blend of the two fuels.

The primary methods for controlling $NO_X$ emissions are evaluated for technical feasibility in the following sections.

- Selective Non-Catalytic Reduction
- Selective Catalytic Reduction
- Low-$NO_X$ Burners

- Water or Steam Injection

- **Selective Non-Catalytic Reduction**

SNCR is a post-combustion $NO_X$ control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with $NO_X$, forming nitrogen and water. The success of this process in reducing $NO_X$ emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to $NO_X$, Below the lower end of the temperature range, the reagent will not react with the $NO_X$ and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the HRSG have an exhaust temperature of approximately 350°F. Even strategically placing the ammonia injection further upstream would probably result only in peak temperatures of around 1,300°P. Such a low temperature would require that additional fuel be combusted at some point in order to raise the temperature to the levels where SNCR will operate effectively. Combustion of the additional fuel would not only increase the $NO_X$ emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

SNCR has not been applied to any combustion turbines according to the RBLC database. Because of the comparatively low exhaust temperatures, fuel and energy requirements, environmental implications and economic considerations, therefore, SNCR is considered to be technically infeasible for the combustion turbines and duct burners under consideration for this Project.

- **Selective Catalytic Reduction**

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert $NO_X$ to nitrogen and water. The function of the catalyst is to lower the activation energy of the $NO_X$ decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system. SCR represents state-of-the-art control for combined cycle, back-end gas turbine $NO_X$ removal. SCR technology is being permitted as LAER and BACT for combined cycle turbines at 2 to 9 ppm $NO_X$ for natural gas and refinery gas. Conventional SCR uses a metal honeycomb or "foil" catalyst support structure and requires the HRSG to reduce flue gas temperatures to less than 600°F.

The Project's turbines will operate with the exhaust gases reaching temperatures over 1,100°F prior to entering the HRSG. Duct burner firing and passage of the flue gasses through the HRSG will lower the temperature of the gas stream to approximately 350°F. By placing the catalyst bed at the correct strategic point within the HRSG, an SCR could effectively operate and reduce $NO_X$ emissions. A disadvantage of this system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased particulate matter emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become particulate matter. SCR can be applied to the combined cycle turbines and duct burners and is considered technically feasible.

- **Low-$NO_X$ Burners**

Low $NO_X$ burners are currently available from most turbine manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing $NO_X$ formation. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher $NO_X$ emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers $NO_X$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. The low $NO_X$ burners for this turbine cannot handle the COG fuel without significant mixing with natural gas. In order to handle the higher levels of hydrogen in the fuel, traditional diffusion combustors are required. As such, low $NO_X$ burners are not considered technically feasible for the combined cycle combustion turbines.

- **Water or Steam Injection**

Steam and water injection work to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With steam injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel ratio of less than one. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3%, but there is an increase in power output typically 5 to 6%) due to the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection depending on the amount of water that is injected. Water/steam injection is available for the combined cycle turbines and under consideration for this Project and is therefore considered technically feasible for the combined cycle combustion turbines.

### 3.1.1 Summary of the Technically Feasible Control Options

Technically feasible $NO_X$ control options for the combined cycle combustion turbines are summarized in Table 4-1. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the combustion turbines.

**TABLE 4.1**
**Summary of Technically Feasible $NO_X$ Control Technologies for Combined cycle Combustion Turbines**

| Control System | | Expected Performance (ppm@15% $O_2$) | Technical Feasibility | Comments |
|---|---|---|---|---|
| Combustion Controls | Low-$NO_X$ Burners | - | Not feasible | Low-$NO_X$ burners cannot handle COG without significant mixing with natural gas |
| | Water Injection | 42 | Feasible | Standard on combustion turbines |
| Post Combustion Controls | SNCR | N/A | Not feasible | Exhaust temperature is too ow |
| | SCR | <9 | Feasible | 7.5 ppm achievable with SCR on COG |
| | XONON | NA | Not feasible | Testing is still underway. Only used on one 1.5-MW unit not operating continuously |
| | EMx | NA | Not feasible | Not proven to work on COG |



### 3.1.2 Rank the Technically Feasible Control Technologies

Add-on controls may be used for combustion turbines firing COG and natural gas. The combustion turbines under consideration come with steam injection as part of their standard packages; therefore, steam injection is assumed as the baseline for the proposed combustion turbines.

The technically feasible $NO_X$ control technologies for the combustion turbines are ranked by control effectiveness in Table 4-2.

**Table 4-2**
**Ranking of Technically Feasible $NO_X$ Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Reduction (%) | Controlled Emission Level (ppm)[a] |
|---|---|---|
| Selective Catalytic Reduction | ~80 | 7.5 |
| Water Injection | NA (baseline) | 42 |

### 3.2 CO BACT ANALYSIS - COMBUSTION TURBINES

The following sections outline the top-down BACT analysis for CO emissions from the Project combustion turbines.

CO is a byproduct resulting from incomplete fuel combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to complete combustion.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Post-combustion CO control involves the use of catalytic oxidation; front-end CO control involves controlling the combustion process to suppress CO formation.

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

- Oxidation Catalyst
- Combustion Control
- EMx™ System

- **Oxidation Catalyst**

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia, for a reaction to occur. The oxidation of CO to $CO_2$ utilizes excess air present in the turbine exhaust. The activation energy required for this reaction to occur is lowered in the presence of a catalyst. Products of combustion are introduced into a catalyst bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and its power generating capabilities. It is expected that the catalyst will be placed in the HRSG where the temperature will be optimal for the catalytic reaction. Therefore, the use of an oxidation catalyst is considered to be a technically feasible method of controlling CO emissions from the proposed combined cycle combustion turbines and duct burners.

- **Combustion Control**

Good combustion practices" include operational and combustion design elements to control the amount and distribution of excess air in the flue gas to ensure there is enough oxygen present for complete combustion. Such control practices applied to the proposed turbines can achieve CO emission levels of 4 ppm at 100% load.

Good combustion practices are considered to be a technically feasible method of controlling CO emissions from the proposed combined cycle combustion turbines and duct burners.

- **EMx™ System**

The EMx™ system was described in the BACT analysis for $NO_X$. The EMx™ system simultaneously oxidizes CO to $CO_2$, NO to $NO_2$, and then absorbs $NO_2$ onto the surface of a catalyst using a potassium carbonate absorber coating VOCs are also removed by the catalyst system. The system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of

EMx™ requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process. Because EMx™ does not use ammonia there are no ammonia emissions from this technology

The demonstrated application for EMx™ is currently limited to combined cycle combustion turbines under approximately 50 MW in size. The EMx™ system has not been demonstrated on any type of fuel other than natural gas on a small combustion turbine. Therefore, the EMx™ system is not considered a technically feasible method of controlling CO emissions from the proposed combined cycle combustion turbines and duct burners.

### 3.2.1 Summary of the Technically Feasible Control Options

The technically feasible CO control options for the proposed combined cycle combustion turbines are summarized in Table 4-2. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

**Table 4-3**
**Ranking of Technically Feasible CO Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Reduction (%) | Controlled Emission Level (ppm)[a] |
|---|---|---|
| Oxidation Catalyst | 90 | 3 |
| Combustion Control | NA (baseline) | 42[b] |

(a) Limits valid for 100% load with duct firing down to 70% load
(b) Average ppm at 100% load with no duct firing on a 70°F day.

The BACT recommended for control of CO emissions from the proposed combustion turbines is good combustion practices and the use of an oxidation catalyst. These controls will meet a CO emission limit of 3 ppm at 15% $O_2$ during steady-state conditions for all loads down to 70% with and without duct firing for all fuels. Compliance with the proposed limit is based on a 3-run stack test average as conducted in accordance with the approved stack testing protocol.

## 3.3 VOC BACT ANALYSIS • COMBUSTION TURBINES

Like CO, VOC is a product resulting from incomplete combustion. VOC emissions occur when a portion of the fuel remains unburned or is only partially burned during the combustion process. With COG and natural gas, some organics are unreacted trace constituents of the gas, while others may be products of the heavier hydrocarbon constituents. Partially-burned hydrocarbons result from poor air-to-fuel mixing prior to, or during, combustion or incorrect air-to-fuel ratios in the combustion turbine.

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

- **EMx™ System**

The EMx™ system can also be evaluated for controlling VOC emissions by up to 20%. The EMx™ system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EMx™ requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process. Because EMx™ does not use ammonia as a reagent, there are no ammonia emissions from this technology. The demonstrated application for EMx™ is currently limited to combined cycle combustion turbines under approximately 50 (MW) in size, combusting natural gas only. The EMx™ system has not been demonstrated on any type of fuel other than natural gas. Therefore, the EMx™ system is not considered a technically feasible method of controlling VOC emissions from the proposed combined cycle combustion turbines and duct burners.

- **Oxidation Catalyst**

As discussed above, oxidation catalysts are a post-combustion technology that do not rely on the introduction of additional chemicals, such as ammonia or urea, for a reaction to occur. The catalyst beds that reduce CO also promote the oxidation of VOC, thereby reducing VOC emissions. Such systems typically achieve a maximum of 35 to 40% removal of VOC, as opposed to the much higher efficiencies achieved for CO reduction. The use of an oxidation catalyst for VOC control is considered to be technically feasible for the combined cycle combustion turbines.

- **Combustion Control**

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure there is enough oxygen present for complete combustion (i.e. controlling the air-to-fuel ratio). Such control practices applied to the proposed combustion turbines can achieve VOC emission levels of approximately 12 ppm when combusting natural gas or COG without an oxidation catalyst for all loads down to 70% without duct firing. Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed combustion turbines.

### 3.3.1 Summary of the Technically Feasible Control Options

The technically feasible VOC control technologies for the proposed combined cycle combustion turbines are ranked by control effectiveness in Table 4-3

**Table 4-4**
**Ranking of Technically Feasible VOC Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Reduction (%) | Controlled Emission Level (ppm)[a] |
|---|---|---|
| Oxidation Catalyst | 40 | 5.1 |
| Combustion Control | NA (baseline) | 12 |

(a) Emission rate for 100% load to 70% load, with and without duct firing.

## 3.4 $SO_2$ BACT ANALYSIS - COMBUSTION TURBINES

Natural gas combustion in combustion turbines results in very low $SO_2$ emissions and as such, $SO_2$ is typically much lower than other uncontrolled criteria pollutants. However, to further reduce $SO_2$ emissions, U. S. Steel has reviewed post-combustion techniques that may be applicable to the combustion turbines and duct burners. The majority of the fuel sulfur combusted in the combustion turbine leaves the turbine as $SO_2$ or is converted to other forms of sulfur such as sulfuric acid ($H_2SO_4$) mist or as ammonium sulfate. The RBLC does not list any add-on controls for $SO_2$ emissions from combustion turbines. However, due to the combustion of COG, RBLC entries for $SO_2$ controls typical of a coal-fired boiler were evaluated for these turbines. U. S. Steel has selected wet scrubbing technology as BACT for this project. An alternate, and equivalent, control scenario that uses dry scrubbing technology is also specified in the air permit.

## 3.5 PM BACT ANALYSIS - COMBUSTION TURBINES

Particulate ($PM/PM_{10}/PM_{2.5}$) emissions from gaseous fuels in combustion sources consist of inert contaminants in gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content, low sulfur content and high combustion efficiency exhibit correspondingly low particulate emissions. COG is proposed as the primary fuel for the combustion turbines with natural gas and blends of the two fuels as back-up.

Particulate control devices are not typically installed on gas turbines. Post-combustion controls, such as ESPs or baghouses, have never been applied to commercial gas-fired turbines. However, due to the expected particulate loading, review of the options for post-combustion control of PM emissions was performed.

- **Dry Electrostatic Precipitator (ESP)**

A dry ESP is a PM control technology that utilizes electrical charges to attract particulate matter present in the gas stream. An ESP consists of negatively charged discharge electrodes and positively charged collection plates. The negatively charged electrodes create a corona of electrical charges transmitting a negative charge to the particulate matter in the gas stream. The negatively charged particulate matter is then attracted to the ESP's positively charged collection plate. Particulate matter accumulates on the collection plate until the plate is mechanically "rapped" causing the PM to fall into hoppers. The PM that collects in the hoppers is then removed by the waste handling system. An ESP consists of a series of the electrical fields described above in order to capture any PM that may be re-entrained in the flue gas stream during rapping. Some emissions during rapping of the last field are unavoidable.

Dry ESPs are intentionally operated at high temperatures to prevent corrosion problems that can result from condensable acid gases. Dry ESPs are technically feasible, demonstrated, and an accepted control technology for reducing PM emissions. Dry ESPs are a technically feasible control technology for filterable PM emissions.

- **Wet Electrostatic Precipitator (WESP)**

A wet ESP (WESP) operates in saturated flue gas conditions where the flue gas is below the dew point of many acid gases and other condensable particulate materials. The collector plates of a WESP are washed with water instead of by "rapping" as in a dry ESP. The typical location of a WESP is downstream of a wet FGD system used for $SO_2$ control. WESP systems have limited demonstrated performance on coal-fired applications. In the few applications that have included a WESP system, the unit fired high-sulfur bituminous coal, and the WESP system was primarily installed for $H_2SO_4$ control.

This project proposes the use of wet scrubber or dry FGD technology for $SO_2$ control, which will reduce $H_2SO_4$ upstream of the particulate fabric filter. If using the dry FGD system, the project will require a baghouse as the downstream particulate control device as an integral part of the system. The particulate loading from the dry FDG system is too high for a dry ESP or WESP. The fabric filter is also needed to provide to residence time required to complete the reaction between the reagent (lime) and the $SO_2$ in the flue gas. If using a wet scrubber for $SO_2$ control, a WESP will be required for particulate control. The technical feasibility of a WESP is therefore predicated on the selected $SO_2$ control.

- **Fabric Filter Baghouse**

A fabric filter baghouse is a particulate collection device that utilizes fabric filters or "bags" to collect particulate matter. The design for a fabric filter baghouse is fairly simple. The flue gas enters an enclosure that contains compartmentalized groups of bags, then is directed through the bags. As the flue gas enters the fabric filter enclosure, particulate matter accumulates on the bags and a "filter cake" is formed on the outside of the bags. The filter cake is a significant part of the filtering media in a fabric filter. The filtered flue gas then exits the baghouse.

When the pressure drop across the baghouse reaches a set level due to filter cake buildup, ambient air is pulsed into the inside of bags to knock the filter cake off the bag and into hoppers below. The particulate matter is then handled by a pneumatic ash handling system and sent to disposal. The bags are operated in a manner to allow for cleaning, maintenance, and repair of one compartment (or group of bags) at a time. Fabric filter baghouses are highly efficient, technically feasible, demonstrated, and an accepted control technology for reducing filterable PM emissions. Fabric filter baghouses are considered a technically feasible control technology for PM emissions from the combustion turbines.

**Summary of the Technically Feasible Control Options**

The technically feasible PM/$PM_{10}$/$PM_{2.5}$ control technologies for the proposed combined cycle combustion turbines are ranked by control effectiveness in Table 4-4

**Table 4-4**
**Ranking of Technically Feasible PM/$PM_{10}$/$PM_{2.5}$ Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Controlled Efficiency (Range, %) |
|---|---|
| Fabric Filter (Baghouse) | 99-99.9[a] |
| WESP | 99 – 99.9[c] |
| Dry ESP | 96.0-99.2[b] |

(a) Based on U.S. EPA Air Pollution Control Technology Fact Sheet for Fabric Filter- Pulse-Jet Cleaned Type (EPA-452/F-03-025) and Fabric Filter - Reverse-Air/Jet Cleaned Type (EPA-452/F-03-026).
(b) Based on U.S. EPA Air Pollution Control Technology Fact Sheet for Dry ESP - Wire-Pipe Type (EPA-452/F-03-027) and Dry ESP - Wire-Plate Type (EPA-452/F-03-028). Note this is based on coal-fired boiler applications with likely much higher particulate loading. There is no direct information on how a dry ESP will perform on a high-sulfur gaseous fuel.
(c) Based on U.S. EPA Air Pollution Control Technology Fact Sheet for Wet Electrostatic Precipitator (ESP) – Wire-Pipe Type (EPA-452/F-03-029) and vendor discussions.

The use of a baghouse or WESP represents BACT for PM/$PM_{10}$/$PM_{2.5}$ control in the proposed combined cycle combustion turbines. These controls will limit PM/$PM_{10}$/$PM_{2.5}$ emissions, including duct burner emissions, to 0.014 lb/MMBtu for COG and natural gas combustion. This emission rate includes front and back half PM/$PM_{10}$/$PM_{2.5}$emissions, takes into account emissions from the ammonium sulfate produced from sulfur and ammonia slip that could be emitted as PM/$PM_{10}$/$PM_{2.5}$, and includes the duct burner emissions that will be emitted out of the turbine stack. Compliance with this limit is based on 3-run stack tests based on an approved stack testing protocol.

## 4.0 METHODS OF DEMONSTRATING COMPLIANCE

Compliance for the emission standards set forth in Installation Permit No. 0052-I019 will be demonstrated by continuous monitoring of $NO_X$ and stack testing. The cogeneration units will be stack tested for nitrogen oxides, $PM_{10}$, carbon monoxide, volatile organic compounds, sulfur dioxide and ammonia. The facility shall continuously monitor control device operating parameters. See the installation permit 0052-I019 for detail.

# 5.0 REGULATORY APPLICABILITY

## 5.1 Allegheny County Health Department Rules and Regulations (Article XXI)

See Permit Application No. 0052-I019, Section 5. The requirements of Article XXI, Parts B and C for the issuance of minor modification installation permits have been met for this facility. Article XXI, Part D, Part E and Part H will have the necessary sections addressed individually.

## 5.2 Testing Requirements

Initial compliance testing and routine testing is required for equipment and processes that can be stack tested, e.g., combustion turbines HRGS units, boilers. Other processes and equipment may have fugitive emissions that cannot be measured with stack tests. The Department will require the use of the best emission factors available until stack test methods or better estimates are developed. See Installation permit 0052-I019, Section V.A.2 for specific test frequencies.

## 5.3 New Source Performance Standards

- **NSPS Subpart D - Standards of Performance for Fossil Fuel-Fired Steam Generating Units**

NSPS Subpart D applies to fossil-fuel-fired steam generating units with heat input ratings greater than 250 MMBtu/hr, which were installed after August 17, 1971. This rule provides standards for PM, $SO_2$, and $NO_X$, as well as emission monitoring and testing procedures. Per 40 CFR 60.40(e), any facility subject to 40 CFR Subpart KKKK is not subject to Subpart D. As the turbines, duct burners, and heat recovery steam generators are subject to Subpart KKKK, this subpart does not apply to those sources. The package boiler will have a heat input rating below 250 MMBtu/hr, and therefore will not be subject to this Subpart. Finally, the dew point heaters do not meet the definition of a steam generating unit and have heat input ratings below 250 MMBtu/hr, and therefore are not subject to this Subpart.

- **NSPS Subpart Da - Standards of Performance for Electric Utility Steam Generating Units**

This subpart applies to electric utility steam generating units with a heat input rating greater than 250 MMBtu/hr, which construction, modification, or reconstruction commenced after September 18, 1978. NSPS Subpart Da contains emission standards for PM, $SO_2$, and $NO_X$, as well as compliance, monitoring, and reporting requirements. 40 CFR 60.40Da(e) exempts heat recovery steam generators with duct burners that are subject to applicable requirements of NSPS Subpart KKKK. As the turbines, duct burners, and heat recovery steam generators are subject to Subpart KKKK, this subpart does not apply to those sources. The package boiler will have a heat input rating well below 250 MMBtu/hr, and therefore will not be subject to this Subpart. Finally, the dew point heaters do not meet the definition of a steam generating unit and have heat input ratings well below 250 MMBtu/hr, and therefore are not subject to this Subpart.

- **NSPS Subpart Db - Standards of Performance for Industrial-Commercial Steam Generating Units**

NSPS Subpart Db applies to steam generating units with heat input ratings greater than 100 MMBtu/hr, which were installed after June 19, 1984. This subpart does not include stationary gas turbines in its definition of steam generating units, however duct burners do meet the definition of steam generating unit. NSPS Subpart KKKK specifically exempts heat recovery steam generators and duct burners regulated under Subpart KKKK from the requirements of NSPS Subpart Db. As the dew point heaters being installed as part of this project do not meet the definition of steam generating units, they are not subject to this Subpart. The proposed package boiler will have a heat input rating greater than 100 MMBtu/hr and therefore will be subject to Subpart Db.

NSPS Subpart Db contains emission standards for PM, $SO_2$, and $NO_X$, as well as compliance, monitoring, and reporting requirements. However, the proposed 140 MMBtu/hr natural gas fired auxiliary boiler is exempt from the emissions limit, pursuant to the following:

- The boiler is exempt from the sulfur dioxide standards per 40 CFR 60.42b(k)(2);
- The boiler is not subject to any PM standards since it is natural-gas fired; and
- The boiler is exempt from $NO_X$ standards per 40 CFR 60.44b(c), which states "This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three)".

The facility has proposed a federally enforceable annual capacity factor of 10 percent (0.10) for natural gas fired boiler. The boiler is also considered a limited use boiler, pursuant to §63.7575.

See Installation permit 0052-I019, Section V.D for the boiler requirements and annual capacity factor restrictions.

- **NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Unit**:

NSPS Subpart Dc applies to a steam generating units and process heaters for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The combustion sources (turbines and duct burners) proposed as part of the Cogeneration Project have a rated heat input greater than the maximum applicability heat input of 100 MMBtu/hr. In addition, NSPS Subpart KKKK specifically exempts heat recovery steam generators and duct burners regulated under Subpart KKKK from the requirements of NSPS Subpart Dc. The dew point heaters do not meet the definition of steam generating units and have heat input ratings below 10 MMBtu/hr. The proposed package boiler will have a heat input rating in excess of 100 MMBtu/hr. Therefore, NSPS Subpart Dc does not apply to those sources.

- **NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines**

40 CFR 60 Subpart GG applies to stationary gas turbines with a peak load heat input rating greater than or equal to 10 MMBtu/ hr which commenced construction, modification, or reconstruction after October 3, 1977. The Cogeneration Project involves the installation of two coke oven gas-fired combustion turbines, each rated at greater than 10MMBtu/hr. However, NSPS Subpart KKKK specifically exempts stationary combustion turbines subject to Subpart KKKK from the requirements of Subpart GG. Therefore, the requirements of NSPS Subpart GG do not apply to this project.

- **NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels**

NSPS Subpart Kb applies to storage vessels with a capacity greater than or equal to 75 cubic meters (approximately 19,800 gallons) used to store volatile organic liquids with a maximum true vapor pressure greater than 15 kilopascals (kPa) that were constructed after July 23, 1984. The storage tank being installed to supply fuel to the emergency fire pump engine is well below the applicability threshold of 19,800 gallons and will store diesel fuel which has a maximum true vapor pressure less than 1 kPa. Therefore, Subpart Kb is not applicable to the proposed storage tank.

- **NSPS Subpart IIII - Stationary Compression Ignition Internal Combustion Engines**

This NSPS applies to owners and operations of stationary compression ignition (Cl) internal combustion engines (ICE) that are not fire pumps and are manufactured after April 1, 2006; fire pumps that are manufactured after July 1, 2006; and CJ IC Es that are modified or reconstructed after July 11, 2005. Units subject to this subpart are also subject to the provisions of 40 CFR 60 Subpart A, except where expressly noted.

NSPS Subpart IIII has specific requirements based on several criteria, including model year, engine displacement, and status as a fire pump. The emergency fire pump engine will be newer than model year 2011 and will need to be certified to meet emission standards for Tier 3 engines. No stack testing is required as a result of this regulation.

Per 40 CFR §60.4207(b), the engine must use non-road diesel fuel with a maximum sulfur content of 15 ppm. As the fire pump engine will be fueled using ULSD, which by definition has a maximum sulfur content of 15 ppm, the unit will meet this requirement. Per 40 CFR §60.4209(a), the unit must install a non-resettable hour meter prior to startup.

- **NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines**

NSPS Subpart KKKK establishes emissions standards for stationary combustion turbines with a peak load heat input greater than or equal to 10 MMBtu/hr that are constructed after February 18, 2005. The applicable heat input threshold is exclusive of fuel burned in the duct burners, though heat recovery steam generators and duct burners are subject to the requirements of this subpart when associated with a turbine that is subject to NSPS Subpart KKKK. As the turbines being installed as part of this project have a heat input greater than 10 MMBtu/hr, they and their associated HRSGs and duct burners are subject to this subpart.

This subpart has emission limits for $NO_X$ and $SO_2$, monitoring, reporting, and testing requirements which apply to these turbines and associated HRSGs and duct burners. The turbines being installed have a maximum heat input rating of approximately 637 MMBtu/hr and can burn coke oven gas, natural gas, or a blend of the two fuels.

The $NO_X$ emission limits in Table 1 of this subpart apply to the stationary combustion turbines. During operation when coke oven gas makes up greater than 50% of the heat input, a $NO_X$ limit of 74 parts per million (ppm) at 15% $O_2$ applies (new turbine firing fuels other than natural gas, rated between 50 and 850 MMBtu/hr). When operating on natural gas, a $NO_X$ limit of 25 ppm at 15% $O_2$ applies. Compliance with the $NO_X$ emission limits will be demonstrated with a continuous emissions monitoring system.

40 CFR §60.4330(a) lists the $SO_2$ emission limit for the turbines on either a gross power output basis (0.90 lb/MWh) or a fuel sulfur concentration basis (0.06 lb/MMBtu). Compliance with the fuel input based $SO_2$ limit requires daily fuel sulfur content monitoring, unless exempted under the provisions of

representative fuel sampling in 40 CFR §60.4365. Compliance with the output based $SO_2$ limit requires annual stack testing.

This subpart specifically exempts turbines regulated under this subpart from the requirements of NSPS GG, and exempts heat recovery steam generators and duct burners regulated under this subpart from the requirements of NSPS Subparts Da, Db, and De.

- **NSPS Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units**

  This NSPS establishes greenhouse gas emission standards and compliance schedules for stationary combustion turbines which commenced construction after January 8, 2014 and have a heat input rating greater than 250 MMBtu/hr of fossil fuel. Fossil fuel is defined as "natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat " This subpart defines natural gas as:

  *A fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) ... natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable $CO_2$ content or heating value. [40 CFR §60.5580]*

  As coke oven gas is not produced for the purpose of creating useful heat and specifically excluded in the definition of natural gas, it does not meet the definition of fossil fuel in this subpart. As these units combust natural gas as a startup and secondary fuel, they are considered fossil fuel-fired stationary combustion turbines. An electric generating unit is defined in this subpart as "any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (i.e. meets the applicability criteria)."

  The applicability criteria in 40 CFR 60.5509(b)(3) exempts combined heat and power units that are limited to no more than 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater, in net-electricity sales. Combined heat and power units are defined as "an electric generating unit that uses a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source." As the turbines will produce both electricity and process steam, they meet the definition of combined heat and power units. The turbines will not have net electricity sales greater than 219,000 MWh and are therefore exempt from this subpart.

## 5.4 National Emission Standards For Hazardous Air Pollutants (NESHAP)

- **NESHAP Subpart L - Coke Oven Batteries**

  NESHAP Subpart L applies to existing and new coke oven batteries. As part of this project no changes are being made to the coke oven batteries at this facility, and thus there are no changes in regulatory applicability of this subpart.

- **NESHAP Subpart YYYY - Stationary Combustion Turbines**

  NESHAP Subpart YYYY applies to stationary combustion turbines located at major sources of HAP. This rule establishes emission and operating limits to reduce HAP emissions and provides compliance requirements for affected units. The turbines being installed as part of this project are gas-fired stationary combustion turbines and subject to this rule; the duct burners and heat recovery steam generators are not subject to the provisions of this rule.

Per 40 CFR §63.6095(d), lean premix and diffusion flame gas-fired stationary combustion turbines must comply with the Initial Notification requirements in 40 CFR 63.6145, however all other requirements of this subpart have been stayed.

On April 2, 2019, U.S. EPA proposed amendments to NESHAP Subpart YYYY, which could have applicable requirements to the proposed combustion turbines depending on the final rule. The proposal was published in the Federal Register on April 12, 2019. U. S. Steel will monitor the rule development and ensure compliance with any final applicable requirements for the proposed units

- **NESHAP Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines (RICE)**

This NESHAP applies to stationary CI and spark-ignition (SI) reciprocating internal combustion engines (RICE) based on engine size, source HAP classification (major or area), and RICE status (new or existing). As the proposed emergency fire pump engine is a CI ICE that will be a new RICE located at a major source of HAP, this engine will be subject to NESHAP Subpart ZZZZ.

The fire pump engine will operate for emergency purposes only. As the emergency fire pump engine will be a new CI ICE less than 250 hp, there are no additional requirements under this subpart.

- **NESHAP Subpart CCCCC - Coke Ovens: Pushing, Quenching, and Battery Stacks**

NESHAP Subpart CCCCC establishes HAP standards for pushing, soaking, quenching, and battery stacks at coke oven batteries. No changes are being made to any of these operations as part of the Cogeneration Project. There are no changes to the regulatory applicability of this subpart.

- **NESHAP Subpart DDDDD - Industrial, Commercial, and Institutional Boilers (Area Source Boiler MACT)**

40 CFR 63 Subpart DDDDD regulates HAP emissions from new, reconstructed and existing industrial, commercial, and institutional boilers and process heaters at major HAP sources. This subpart defines a boiler as:

*An enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(l} of the Clean Air Act. Waste heat boilers are excluded from this definition.*
*[40 CFR §63.7575]*

Waste heat boilers are specifically excluded from the definition of boilers in this subpart. Waste heat boilers are defined as follows:

*A device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct* *burners are sometimes used to increase the temperature of the incoming hot exhaust gas. [40 CFR §63.7575]*

The turbines being installed as part of this project do not meet the definition of boiler, and the associated heat recovery steam generators and duct burners are explicitly excluded from the definition of boiler. However, the proposed package boiler will meet the definition of a boiler as described above and will be subject to the rule. Because this unit will be fired exclusively with natural gas and considered a limited use boiler, it will be subject to once 5-year tune-ups and associated recordkeeping and reporting requirements under the rule.

Under the rule, process heaters are defined as follows:

*An enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. [40 CFR §63.7575]*

The dew point heaters proposed as part of this project do meet the definition of process heaters under the rule. Because these units will be designed to burn natural gas exclusively and will be less than 5.0 MMBtu/hr heat input, the only requirement under the rule will be to conduct a tune up once every 5 years as specified in §63.7540.

### 5.5 Risk Management Plan; CAA Section 112(r):

The facility currently has a risk management plan. This project will have no effect on the RMP or the rule applicability.

### 5.6 Greenhouse Gas Reporting (40 CFR Part 98):

If the facility emits 25,000 metric tons or more of carbon dioxide equivalent ($CO_2e$) in any 12-month period, the facility shall submit reports to the US EPA in accordance with 40 CFR Part 98.

### 5.7 Air Toxics Guidelines:

The emissions increase associated with the project is less than the *de minimis* levels, therefore, the ATG does not apply.

## 6.0 EMISSIONS SUMMARY:

**TABLE VII-1: Emission Limitations Summary**

| POLLUTANT | ANNUAL EMISSION LIMIT (tons/year)* |
|---|---|
| Particulate Matter | 12.89 |
| Particulate Matter <10 µm ($PM_{10}$) | 44.50 |
| Particulate Matter <2.5 µm ($PM_{2.5}$) | 44.35 |
| Nitrogen Oxides ($NO_X$) | 287.55 |
| Sulfur Oxides ($SO_X$) | 234.56 |
| Carbon Monoxide (CO) | 86.32 |
| Volatile Organic Compounds (VOC) | 31.87 |
| Ammonia ($NH_3$) | 18.97 |
| Lead | 0.0066 |
| Total Hazardous Air Pollutants (HAP) | 30.26 |
| Greenhouse Gases ($CO_2e$) | 926,993 |

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

## RECOMMENDATION

All applicable Federal, State, and County regulations have been addressed in the permit application, and the provisions of Article XXI, §2102.04.k relating to 'Restrictions on Sources with Violations' does not apply to this installation permit because paragraph §2102.04.k.1 states that: This subsection does not apply to sources installing air pollution control equipment, or project that do not increase total potential air emissions of any regulated pollutant at those sources. This project includes the shutdown of Boilers 1, 2 & R1 and the installation of cogeneration units, which will result in overall decrease in total potential air emissions.

The Installation Permit for U. S. Steel, Clairton should be approved with the emission limitations and terms & conditions in Permit No. 0052-I019.