

Facility Name: **Mid-Georgia Cogen**
 City: Kathleen
 County: Houston
 AIRS #: 04-13-153-00042

Application #: TV-602161
 Date Application Received: November 17, 2021
 Permit No: 4931-153-0042-V-06-0

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Introduction

This narrative is being provided to assist the reader in understanding the content of referenced operating permit. Complex issues and unusual items are explained here in simpler terms and/or greater detail than is sometimes possible in the actual permit. The permit is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. and (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

I. Facility Description

A. Facility Identification

1. Facility Name: Mid-Georgia Cogen

2. Parent/Holding Company Name

Mid-Georgia Cogen Limited Partnership

3. Previous and/or Other Name(s)

None identified.

4. Facility Location

200 Oaky Woods Road, Kathleen, Georgia 31047

5. Attainment, Non-attainment Area Location, or Contributing Area

The facility is located within Houston County which is designated an attainment area for all criteria pollutants.

B. Site Determination

Mid-Georgia Cogen facility is adjacent to and supplies steam to food manufacturing facility, Frito-Lay. Both facilities are deemed to be separate sources under Title V because there is no common control between the two entities at any level. The Frito-Lay facility is a synthetic minor source (AIRS No. 153-00035). There are no other facilities which could possibly be contiguous or adjacent and under common control.

C. Existing Permits

Table 1 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a comparative review of form A.6, Current Permits, of the Title V application and the "Permit" file(s) on the facility found in the Air Branch office.

Table 1: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/Effectiveness	Purpose of Issuance
4931-153-0042-V-05-0	May 22, 2017	Title V Renewal

D. Process Description

1. SIC Codes(s)

4931

The SIC Code(s) identified above were assigned by EPD's Air Protection Branch for purposes pursuant to the Georgia Air Quality Act and related administrative purposes only and are not intended to be used for any other purpose. Assignment of SIC Codes by EPD's Air Protection Branch for these purposes does not prohibit the facility from using these or different SIC Codes for other regulatory and non-regulatory purposes.

Should the reference(s) to SIC Code(s) in any narratives or narrative addendum previously issued for the Title V permit for this facility conflict with the revised language herein, the language herein shall control; provided, however, language in previously issued narratives that does not expressly reference SIC Code(s) shall not be affected.

2. Description of Product(s)

Mid-Georgia Cogeneration facility generates commercial power and steam.

3. Overall Facility Process Description

Mid-Georgia Cogen operates two combined cycle combustion turbines (T001 and T002) each rated at a nominal capacity of 133 MW and one auxiliary boiler (B001) rated at 93.7 MMBtu/hr. The turbines and boiler are fired primarily with natural gas and with low sulfur distillate fuel oil as a backup. The combustion turbines include heat recovery steam generator (HRSG) systems for waste heat capture and steam production to power a 100 MW steam turbine and provide process steam to nearby food products manufacturing plant, Frito-Lay. Selective catalytic reduction (SCR) is used for final control of NO_x. The auxiliary boiler (B001) provides process steam to a host facility when both combustion turbines are off-line.

4. Overall Process Flow Diagram

The facility provided a process flow diagram in their Title V permit application.

E. Regulatory Status

1. PSD/NSR

The facility remains a major source under PSD regulations because it is one of the 28 named source categories and has the potential to emit NO_x, CO, VOC, PM, and SO₂ in amounts exceeding 100 tpy.

2. Title V Major Source Status by Pollutant

Table 2: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	y	✓		
PM ₁₀	y	✓		
PM _{2.5}	y	✓		
SO ₂	y	✓		
VOC	y	✓		
NO _x	y	✓		
CO	y	✓		
TRS	n/a			
H ₂ S	n/a			
Individual HAP	y			✓
Total HAPs	y			✓

3. MACT Standards

The facility is not subject to any MACT regulations.

4. Program Applicability (AIRS Program Codes)

Program Code	Applicable (y/n)
Program Code 6 - PSD	y
Program Code 8 – Part 61 NESHAP	n
Program Code 9 - NSPS	y
Program Code M – Part 63 NESHAP	n
Program Code V – Title V	y

Regulatory Analysis

II. Facility Wide Requirements

A. Emission and Operating Caps:

None applicable.

B. Applicable Rules and Regulations

Not applicable.

C. Compliance Status

The facility did not indicate any noncompliance issues.

D. Permit Conditions

None applicable.

III. Regulated Equipment Requirements

A. Equipment List for the Process

Emission Units		Applicable Requirements/Standards	Air Pollution Control Devices	
ID No.	Description		ID No.	Description
Equipment Group G1CT	Combustion Turbines T001 and T002	391-3-1-.02(2)(b)	DRY1	DLN**
		391-3-1-.02(2)(g)	DRY2	DLN
		40 CFR 52.21		
		40 CFR 60 Subpart A	WAT1	WI***
		40 CFR 60 Subpart GG	WAT2	WI
		40 CFR 64		
		Acid Rain	SCR1	SCR****
		CSAPR	SCR2	SCR
B001	Auxiliary Nebraska Boiler	391-3-1-.02(2)(d)	AUX1	DLN and FGR^
		391-3-1-.02(2)(g)		
		40 CFR 52.21		
		40 CFR 60 Subpart A		
		40 CFR 60 Subpart Dc		

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards and corresponding permit conditions are intended as a compliance tool and may not be definitive.

**DLN = Dry Low NOx burners

***WI = Water Injection

**** SCR = Selective Catalytic Reduction

^ FGR = Flue Gas Recirculation

B. Equipment & Rule Applicability

Equipment Group G1CT - Combustion Turbines

Mid-Georgia Cogen operates two Westinghouse 501D5A combustion turbines, T001 and T002, each with a power output rating of approximately 133 MW. These units are fired with pipeline quality natural gas, as the primary fuel, and low sulfur distillate fuel oil, as the backup fuel. Each turbine utilizes DLN burners, WI, and SCR to minimize NOx emissions. The temperature of the turbine exhaust stream is reduced, prior to the SCR, by a HRSG.

Each combustion turbine is subject to the requirements of 40 CFR 60, Subpart GG - "Standard of Performance for Stationary Gas Turbines" because they have a heat input at peak load equal to or greater than 10.7 gigajoules per hour [10.14 MMBtu/hr], based on the lower heating value of the fuel fired; and because the turbines were constructed after October 3, 1977. The NSPS General Provisions [40 CFR 60, Subpart A] also apply to each turbine. In addition, each turbine is subject to the requirements of 40 CFR 52.21, Prevention of Significant Deterioration, because the facility has a potential to emit greater than or equal to 100 tons per year of a criteria pollutant (this is one of the 28 named sources because of steam production).

The allowable PM emission rate from this Equipment Group is established by 40 CFR 52.21(j) [i.e., PSD] which specifies the BACT PM limit for each combustion turbine. These emission units are not subject to Georgia Rule 391-3-1-.02(2)(d) because they do not meet the definition of "fuel burning equipment" in the Georgia Rules.

The allowable NO_x emission rate from this Equipment Group is specified by NSPS Subpart GG [40 CFR 60.332(b)] and by PSD. PSD specifies the most stringent NO_x emission rate, and the PSD emissions limit subsumes the NSPS Subpart GG emissions limit.

The allowable fuel sulfur content limit for fuel combusted by the turbines in this Equipment Group is specified by NSPS Subpart GG [40 CFR 60.333], PSD, and by Georgia Rule 391-3-1-.02(2)(g). PSD specifies the most stringent fuel sulfur content limit, and the PSD emissions limit subsumes the NSPS Subpart GG and Georgia Rule (g) content limits.

Sulfur dioxide emissions from the turbines are regulated by the Acid Rain Program. Mid-Georgia Cogen must obtain, in the open market, the number of SO₂ allowances that correspond to their annual SO₂ emissions.

The allowable CO and VOC emission rates from this Equipment Group are established only by PSD.

The allowable opacity limit is specified by PSD and Georgia Rule 391-3-1-.02(2)(b). Georgia Rule (b) applies to this Equipment Group because the turbines are subject to at least one other emission limitation in Georgia Rule 391-3-1-.02(2). PSD specifies the most stringent opacity standard, and the PSD emissions limit subsumes the Georgia Rule (b) requirement.

Auxiliary Boiler B001

This auxiliary boiler produces process steam in the event that Equipment Group G1CT is off-line. The boiler is rated at 93.7 MMBtu/hr and was manufactured in 1997. The boiler is fired with natural gas, as the primary fuel, and low sulfur distillate fuel oil, as the backup fuel. B001 utilizes DLN with flue gas recirculation (FGR) to minimize NO_x emissions.

Boiler B001 is subject to the requirements of 40 CFR 60, Subpart Dc - "Standard of Performance for Small Industrial- Commercial-Institutional Steam Generating Units" because it has a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr; and because the boiler was constructed after June 9, 1989. The NSPS General Provisions [40 CFR 60, Subpart A] also apply to this boiler. In addition, the boiler is subject to the requirements of 40 CFR 52.21, Prevention of Significant Deterioration, because the facility has a potential to emit greater than or equal to 100 tons per year of a criteria pollutant.

The allowable PM emissions limit from B001 is established by PSD and Georgia Rule 391-3-1-.02(2)(d)2.(ii). PSD specifies the most stringent PM emissions limit, and PSD subsumes the Georgia Rule (d) limit.

The allowable opacity limit is specified by PSD and Georgia Rule 391-3-1-.02(2)(d)3. The limit specified by both are identical, namely 20 percent.

The allowable fuel sulfur content limit for fuel combusted by this boiler is specified by NSPS Subpart Dc [40 CFR 60.42c(d)], PSD, and Georgia Rule 391-3-1-.02(2)(g). The most stringent fuel sulfur content limit is specified by PSD, and the PSD requirements subsumes the limit imposed by NSPS Subpart Dc and Georgia Rule (g).

The allowable NO_x, CO, and VOC emission rates from this boiler are established only by PSD.

Non-Applicability determination of 40 CFR 63 Subpart JJJJJJ - National Emission Standards for Area Sources: Industrial/Commercial/Institutional Boilers

Auxiliary boiler (B001) rated at 93.7 MMBtu/hr fires natural gas as primary fuel and low sulfur distillate fuel oil as backup fuel. 40 CFR 63 Subpart JJJJJJ is not applicable to gas-fired boiler. Definition of gas-fired boiler under Subpart JJJJJJ is as follows:

“Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.”

Since boiler B001 falls under definition of gas-fired boiler, it is not subject to 40 CFR 63 Subpart JJJJJJ.

C. Permit Conditions

Permit Condition 3.2.1 states the NSPS Subpart 6J Avoidance requirements e.g., the definition of gas-fired boiler for the boiler B001.

Permit Condition 3.3.1 limits emissions from Equipment Group G1CT when burning fuel oil.

Permit Condition 3.3.2 limits emissions from Equipment Group G1CT when burning natural gas.

Permit Condition 3.3.3 limits the fuel oil sulfur content for fuel oil burned in the turbines.

Permit Condition 3.3.4 limits emissions from boiler B001 when burning fuel oil.

Permit Condition 3.3.5 limits emissions from boiler B001 when burning natural gas.

Permit Condition 3.3.6 limits the weight percent sulfur content of fuel oil burned in boiler B001 to 0.05 percent.

Permit Condition 3.3.7 states that Equipment Group G1CT must comply with 40 CFR 60 Subpart A and Subpart GG.

Permit Condition 3.3.8 allows operation of either turbine in Equipment Group G1CT above its rated capacity for no more than two hours per day while firing natural gas.

Permit Condition 3.3.9 restricts operation of the turbines below 79 MW, except during periods of startup or shutdown.

Permit Condition 3.3.10 requires installation of dry low NO_x combustors for natural gas combustion and water injection for distillate fuel oil combustion with selective catalytic reduction add-on control equipment for either fuel for each turbine.

Permit Condition 3.3.11 requires installation of dry low NOx burners and flue gas recirculation for boiler B001.

Permit Condition 3.3.12 requires boiler B001 to comply with 40 CFR 60 Subpart A and Subpart Dc.

Permit Condition 3.3.13 limits visible emissions from boiler B001.

Permit Condition 3.4.1 states the applicable requirements of Georgia Rule (d) for the boiler B001.

IV. Testing Requirements (with Associated Record Keeping and Reporting)**A. General Testing Requirements**

The permit includes a requirement that the Permittee conduct performance testing on any specified emission unit when directed by the Division. Additionally, a written notification of any performance test(s) is required 30 days (or sixty (60) days for tests required by 40 CFR Part 63) prior to the date of the test(s) and a test plan is required to be submitted with the test notification. Test methods and procedures for determining compliance with applicable emission limitations are listed and test results are required to be submitted to the Division within 60 days of completion of the testing.

B. Specific Testing Requirements

Not applicable.

V. Monitoring Requirements

A. General Monitoring Requirements

Condition 5.1.1 requires that all continuous monitoring systems required by the Division be operated continuously except during monitoring system breakdowns and repairs. Monitoring system response during quality assurance activities is required to be measured and recorded. Maintenance or repair is required to be conducted in an expeditious manner.

B. Specific Monitoring Requirements

The Mid-Georgia Cogen facility consists of two combustion turbines subject to the requirements of Subpart GG and one auxiliary boiler subject to the requirements of Subpart Dc. The facility was permitted under PSD regulations and, therefore, has more restrictive limits than those in the subparts and limits for pollutants not regulated in the subparts.

1. Equipment Groups (all subject to the same monitoring requirements):

Equipment Group GICT - Combustion Turbines

The combustion turbines have limits for nitrogen oxides, carbon monoxide, particulate matter, volatile organic compounds, and opacity. Fuel oil combusted in the turbines is limited to 0.05 percent sulfur, and the turbines are required to operate at a minimum of 75 percent of their rated capacity. The turbines are also subject to the monitoring requirements of the Acid Rain Rule and have nitrogen oxides and oxygen Continuous Emission Monitoring Systems (CEMS). The CEMS are utilized to demonstrate compliance with the nitrogen oxides limit (permit condition 5.2.1).

Performance tests were conducted for particulate matter and visible emissions on the turbines operating at 100 percent of rated capacity. Visible emissions were zero percent opacity for all readings and particulate matter emissions were less than 15 percent of the allowable emissions for all tests conducted (12.79% of allowable emissions on Turbine No. 2 burning fuel oil). These tests represent worst-case emission levels for these pollutants. Since the tests indicated emissions well below the allowable limits, the likelihood of emissions being above the limits is minimal and no monitoring is required.

Tests for emissions of carbon monoxide were also conducted with the turbines operating at 100 and 75 percent of rated capacity. Carbon monoxide emissions were less than 85 percent of the allowable emission limits for all tests (83.17% of allowable emissions on Turbine No. 2 at 75 percent load burning natural gas). Emissions of carbon monoxide are dependent upon temperature in the turbine combustion chamber and increase as the temperature decreases. Additionally, the combustion temperature for a given turbine load is also very consistent and only decreases with a decrease in turbine load. Since 75 percent load is the minimum permitted operating level (permit condition 3.3.9) and the testing showed compliance with the allowable limit at this load, monitoring turbine load is sufficient for assuring compliance with the carbon monoxide limit.

Estimated emissions of nonmethane hydrocarbons, as methane, from a gas-fired turbine with Selective Catalytic Reduction (using AP-42 emission factors) are 2.5 ppm corrected to 15 percent oxygen (42

percent of allowable). Estimated emissions of total organic carbon, as methane, from an uncontrolled distillate oil-fired turbine are 12.6 ppm corrected to 15 percent oxygen (42 percent of allowable). Emissions of total organic compounds are dependent upon temperature in the turbine combustion chamber and increase as the temperature decreases in much the same way as do carbon monoxide emissions. Since the minimum permitted operating level is 75 percent load and since emissions of total organic carbon follow the same trends as does carbon monoxide, monitoring turbine load is sufficient for assuring compliance with the limit.

Sulfur content of the fuel oil for the turbines is limited to 0.05 percent which is much lower than the Subpart GG sulfur limit of 0.8 percent. Permit Condition 5.2.2 was updated to incorporate the specific language on monitoring fuel sulfur content was removed from Condition No. 5.2.2, so that the Permittee may use any method allowed by 40 CFR 60.334. Monitoring of nitrogen content is still not required since the Permittee is not using an allowance for fuel-bound nitrogen for compliance with 40 CFR 60. The requirements of 40 CFR 60.334(b) (monitoring of sulfur and nitrogen fuel content) were moved in 2004 to 40 CFR 60.334(h) (see 69 FR 41360) and the requirements were changed to allow more options for monitoring of sulfur content.

The turbines are permitted to operate at greater than the rated capacity. Operation at this level, however, is limited to no more than two hours per day. The minimum permitted turbine load is 79 MW. To monitor for the load limits, the Permittee must determine the electrical output of the turbine for each hour of operation for each operating day. The Permittee must then report each hour when the electrical output is less than 79 MW and each day when the turbine operates at greater than the theoretical maximum output for greater than two hours.

2. Individual Equipment:

Emission Unit - Boiler B001

The auxiliary boiler has limits for nitrogen oxides, carbon monoxide, particulate matter, volatile organic compounds, and opacity. Emission test results indicated the possibility that the emission limits will be exceeded, and monitoring for nitrogen oxides is necessary. A Continuous Emissions Monitoring System (CEMS) was installed to monitor Nitrogen Oxides emissions (Permit Condition 5.2.1).

Sulfur content of the fuel oil for the boiler is limited to 0.05 percent. Fuel supplier certifications will be used to monitor fuel sulfur and a certification by the supplier that the fuel oil meets the specifications for diesel fuel Grades Low sulfur No. 1-D or Low Sulfur No. 2-D contained in ASTM D975 is required.

Permit Condition 5.2.1 requires NO_x CEMs for T001, T002, and B001.

Permit Condition 5.2.2 requires no determination of nitrogen content for those items requiring a NO_x CEMS.

Permit Condition 5.2.3 requires the determination of electrical output for T001 and T002 for each hour of operation.

Permit Conditions 5.2.4, 5.2.5, 5.2.6 and 5.2.7 state the CAM requirements for T001 and T002.

Permit Condition 5.2.8 state the response requirements after detecting an excursion or exceedance as defined in Condition 6.1.7b. or 6.1.7c.

Permit Condition 5.2.9 state the response requirements should the facility identify a failure to achieve compliance with an emission limitation or standard for which the approved monitoring in Condition 5.2.5 did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions.

Permit Conditions 5.2.10 and 5.2.11 state the Method 9 performance test or alternative test requirements when fuel oil is burned in the boiler B001.

C. Compliance Assurance Monitoring (CAM)

The Permittee submitted a CAM Plan with the permit application. The CAM Plan identifies 3 pollutant-specific emissions units (PSEUs). Two PSEUs are listed in the following table and in Condition No. 5.2.4. Boiler B001 is not subject to CAM because its uncontrolled emissions of NOx are below the Title V threshold of 100 tons per year and therefore it is not a PSEU.

<i>PSEU</i>	<i>Pollutant</i>	<i>Control Device</i>
T001 – combustion turbine	NOx	Water Injection, Selective Catalytic Reduction
T002 – combustion turbine	NOx	Water Injection, Selective Catalytic Reduction

Each of the PSEUs is equipped with a low-NOx burner. However, a low-NOx burner is not a control device as defined in Part 64.1. Both of the PSEUs are subject to a NOx emission standard. The controlled NOx levels for the units are less than the applicable standards. The pre-control-device NOx emissions levels for the PSEUs are greater than 100 tons per year. The Part 64 applicability threshold in an attainment area for pre-control-device emissions of NOx is 100 tons per year. The PSEUs are subject to Part 64 for NOx emissions. The applicable elements of the Permittee's CAM plan are included in Condition Nos. 5.2.4 through 5.2.9.

VI. Record Keeping and Reporting Requirements**A. General Record Keeping and Reporting Requirements**

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all information related to deviations from the applicable requirements. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a quarterly basis.

B. Specific Record Keeping and Reporting Requirements

Permit Condition 6.2.1 includes recordkeeping and reporting requirement for Boiler B001 from 40 CFR 60 Subpart Dc.

Permit Condition 6.2.1 requires the facility to submit semiannual report for fuel oil certification for Boiler B001 in accordance with 40 CFR 60.48c(j). It has also been updated to incorporate alternative periodic report deadlines; these new deadlines replace the former 30-day deadlines. Alternative reporting deadlines are allowed per 40 CFR 70.6 and 40 CFR 60.19(f).

Permit Condition 6.2.2 includes requirements from existing Permit Condition 5.2.4. Existing Permit Condition 5.2.4 requires monitoring of low sulfur fuel oil.

Permit Condition 6.2.3 includes recordkeeping of the periodic opacity monitoring done on boiler B001 and reporting of any excess emissions for opacity.

Permit Condition 6.2.4 includes reporting of results of any visible emissions observations conducted in accordance with Permit Conditions 5.2.10 and/or 5.2.11.

VII. Specific Requirements

A. Operational Flexibility

- Not applicable.

B. Alternative Requirements

- None applicable.

C. Insignificant Activities

See Permit Application on GEOS website.
See Attachment B of the permit

D. Temporary Sources

- None applicable.

E. Short-Term Activities

- None applicable.

F. Compliance Schedule/Progress Reports

- No compliance schedule or progress report are necessary at this time.

G. Emissions Trading

- The facility is not involved in any emissions trading programs.

H. Acid Rain Requirements

- Title IV is applicable
- Requirements are included in subsection 7.9 of this permit

I. Stratospheric Ozone Protection Requirements

The facility has indicated in the permit renewal application that it is subject to Title VI. Relevant conditions are included in Subsection 7.11 of the permit.

J. Pollution Prevention

- No pollution prevention requirements are associated with this renewal

K. Specific Conditions

- indicate new facility-specific conditions, not covered elsewhere

L. Cross State Air Pollution Rule (CSAPR) Allowance Trading Program Requirements

CSAPR replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR). A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement the Clean Air Act requirements concerning the transport of air pollution across state boundaries. This Cross-State Air Pollution Rule is designed to implement these Clean Air Act requirements and respond to the court's concerns. CSAPR took effect January 1, 2015; CAIR was implemented through the 2014 compliance periods, and then replaced by the CSAPR.

Permit Condition 7.15.1 identifies the units subject to CSAPR and the applicable CSAPR Programs.

Permit Condition 7.15.2 outlines the Annual NO_x, SO₂ and Ozone Season NO_x Emissions Requirements

Permit Condition 7.15.3 outlines the monitoring, reporting and recordkeeping requirements associated with CSAPR.

VIII. General Provisions

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution.

Template Condition 8.8.2 has been updated to direct records, compliance certifications, and monitoring data submittals to the Air and Radiation Division.

Addendum to Narrative

The 30-day public review started on month day, year and ended on month day, year. Comments were/were not received by the Division.