NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date:

Region: Mooresville Regional Office
County: Catawba
NC Facility ID: 1800073
Inspector's Name: Melinda Wolanin
Date of Last Inspection: 01/12/2022
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Marshall Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Marshall Steam Station
8320 East NC Hwy 150
Terrell, NC 28682

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 02Q .0501(b)(1), 02Q .0513, 02D .0501(e), 02D .0519, 02D .0521, 02D .0606, 02D .1100, 02D .1111 (Subparts UUUUU, DDDDD and ZZZZ), 02D .0530(u), 02Q .0402, 02D .0614, 02D .0503, 02D .0516, 02D .0510, 02D .0540, 02D .0524 (Subparts OOO, Y and IIII), 02Q .0317 (avoidance for 02D .0530), 02D .0515
NSPS: NA
NESHAP: NA
PSD: NA
PSD Avoidance: NA
NC Toxics: NA
112(r): NA (General Duty Clause)
Other: CSAPR

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Joseph (Scott) La Sala Senior EHS Professional (828) 478-7820 8320 East NC Hwy 150 Terrell, NC 28682	Jeffrey Flanagan General Manager III (828) 478-7600 8320 East NC Highway 150 Terrell, NC 28682	Daniel Markley Lead Environmental Specialist (704) 382-0696 526 South Church Street Charlotte, NC 28202

Application Data

Application Numbers: 1800073.22A, .22B, .21A
Date Received: 01/28/2022 (.22A and .22B) and 09/29.2021 (.21A)
Application Type: Renewal (.22A and .22B), and Modification (.21A)
Application Schedule: TV-Renewal (.22A), Title IV (.22B), and TV-Sign-501(b)(2) Part II (.21A)

Existing Permit Data

Existing Permit Number: 03676/T58
Existing Permit Issue Date: 05/04/2021
Existing Permit Expiration Date: 07/31/2022

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2020	3086.51	5991.98	85.09	2045.99	237.14	23.17	8.99 [Hydrogen chloride (hydrochlori]
2019	4877.96	8752.83	94.30	2167.26	293.68	26.17	11.80 [Hydrogen chloride (hydrochlori]
2018	3621.01	8836.06	102.16	2274.58	326.18	27.65	12.81 [Hydrogen chloride (hydrochlori]
2017	4362.01	9545.81	111.17	2446.55	346.03	29.70	13.69 [Hydrogen chloride (hydrochlori]
2016	4919.01	9389.15	117.18	2917.11	375.48	31.35	14.58 [Hydrogen chloride (hydrochlori]

Review Engineer: Ed Martin

Review Engineer's Signature: **Date:**

Comments / Recommendations:
Issue 03676/T59
Permit Issue Date:
Permit Expiration Date:

Chronology

January 28, 2022	Title V renewal application 1800073.22A and Title IV renewal application 1800073.22B were received and considered complete for processing.
February 2, 2022	Dan Markley was asked if DEC would agree to remove the COMS option from the permit for compliance with the PM limits in 02D .0521 and 02D .0606 (and previously in 02D .0536) since a PM CEMS is required by the MATS rule and COMS have not been used for several years. This would avoid the need for a new CAM condition for using the COMS option for 02D .0503 which is now being added and would simplify the permit. Mr. Markley stated they are in favor of removing the COMS option throughout the permit.
April 4, 2022	Sent the draft permit for Supervisor's review.
April 27, 2022	Sent the draft permit to the Stationary Source Compliance Branch, Applicant, and the Mooresville Regional Office for review.
xx, 2022	Sent the draft permit to 30-day public notice and 45-day EPA review.
xx, 2022	Public notice period ended.
xx, 2022	EPA's comment period ended.
xx, 2022	Permit was issued.

I. Purpose of Applications

Application 1800073.22A
The purpose of this permit application is to renew the existing Title V permit pursuant to 02Q .0513. The renewal application was received on January 28, 2022, at least six months before the July 31, 2022 expiration date of the current permit; therefore, the application was filed in a timely manner and the application shield pursuant to 15A NCAC 02Q .0512(b)(1) remains in effect. This renewal permit is being issued for another 5-year term and will expire 5 years from the date of issuance.

DEC requested the insignificant activities list be revised to remove I-13.

This renewal permit is required to go through a 30-day public notice and a 45-day EPA review period prior to issuance.

The following application was consolidated with this application:

Application 1800073.22B (consolidated with application 1800073.22A)
DEC's Acid Rain Permit Application was received January 28, 2022, for renewal of the acid rain permit for the four coal-fired boilers (ID Nos. ES-1 through ES-4).

Application 1800073.21A (consolidated with application 1800073.22A)
This application is the second step of the two-step Title V 02Q .0501(b)(2) Part II significant modification process for the natural gas co-firing project for Units 1 through 4 permitted in Permit No. 03676T57. The technical review for the Part I application (1800073.18B) is attached to this document.

With this application, DEC requested the removal the following sections of the permit that are no longer applicable since regulation 15A NCAC 02D .0536 was repealed effective November 1, 2020:

2.1 A.4	15A NCAC 02D .0536: PARTICULATE EMISSIONS FROM ELECTRIC UTILITY BOILERS
2.1 A.5	15A NCAC 02D .0536: ANNUAL AVERAGE OPACITY FOR ELECTRIC UTILITY BOILERS

2.1 A.6 15A NCAC 02D .0535: EXCESS EMISSIONS REPORTING AND MALFUNCTIONS

2.1 A.12 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING for 15A NCAC 02D .0536: PARTICULATE EMISSIONS FROM ELECTRIC UTILITY BOILERS

Along with removal of the 02D .0536 rules above, since the affected units are subject to the MACT standards in 40 CFR Part 63 Subpart UUUUU (i.e., the MATS rule) under 02D .1111, the provisions of 02D .0535 no longer apply as previously specified in 02D .0536 and as required for all electric utility boiler units as specified in 15A NCAC 02D .0535(d). Therefore, DEC requests that all references to a Malfunction Abatement Plan be removed from the permit.

In addition, previous monitoring for the COMS option in Section 2.1 A.4.e for PM when the PM COMS option was used was based on the 02D .0614 CAM condition in Section 2.1 A.12 in order to assure continuous compliance with 15A NCAC 02D .0536. With removal of 02D .0536, 02D .0614 no longer applies.

II. Facility Description

Duke Energy Carolinas' (DEC) Marshall Steam Station is an electric utility that generates electrical power. The Marshall Steam Station is permitted for four No. 2 fuel oil/natural gas/coal-fired electric utility boilers (ID Nos. ES-1, ES-2, ES-3, ES-4) and various supporting equipment.

III. Permit Changes

The following changes were made to Air Permit No. 03676T58:*

Old Page No.	Old Section	New Page No.	New Section	Description of Changes
Cover	--	Cover	--	Added new cover letter with new format. Amended permit numbers and dates. Added page: "Notice Regarding the Right to Contest A Division of Air Quality Permit Decision."
--	TOC	--	TOC	Revised the Acid Rain Permit Application date.
4-7	1, table of permitted emission sources	4-7	1, table of permitted emission sources	Removed "CAM" designation for ES-1 through ES-4. Removed footnote +.
9	2.1 A, regulation table	9	2.1 A, regulation table	Removed 02D .0536 (for particulate matter and visible emissions), 02D .0535, 02D .0614, and 02Q .0504. Added 02D .0503. Removed "Federally Enforceable Only" for 40 CFR Part 97.
11	2.1 A.3	11	2.1 A.3	Revised 02D .0521 to remove the COMS option.
12	2.1 A.4	--	--	Removed this section.
14	2.1 A.5	--	--	Removed this section.
15	2.1 A.6	--	--	Removed this section.

16	2.1 A.7	11	2.1 A.4	Removed minor modification note *. Revised 02D .0606 to remove the COMS option. Replaced footnote *** in Section 2.1 A.7.a with a definition of Total Source Operating Time instead of referring to the %EE and %MD calculations when operating less than 2200 hours during any quarter (which is addressed when DAQ reviews the quarterly EERs on a case-by-case basis and is no longer needed).
17	2.1 A.8	13	2.1 A.5	Removed “Federally Enforceable Only”
17	2.1 A.9	--	--	Removed this previously “RESERVED” section.
17	2.1 A.10	--	--	Removed this previously “RESERVED” section.
17	2.1 A.11	--	--	Removed this previously “RESERVED” section.
18	2.1 A.12	--	--	Removed this section.
20	2.1 A.13	--	--	Removed this previously “RESERVED” section.
--	--	21	2.1 A.10	Added 02D .0503**.**
--	--	24	2.1 B.3.a	Added this paragraph.
32	2.1 C.2.e	27	2.1 C.2.e	Revised reporting to eliminate reference to the report described in Section 2.1 A.7.d.
45	2.1 K, regulation table	40	2.1 K, regulation table	Added 15A NCAC 02D .0540.
47	2.1 L	42	2.1 L	Removed statement that the conditions are not shielded. Removed 02Q .0504 from the regulations table. Revised the 02D .0503 pounds per million Btu heat input limit in the regulations table.
50	2.1 M	45	2.1 M	Removed statement that the conditions are not shielded. Removed 02Q .0504 from the regulations table.
51	2.1 N	46	2.1 N	Removed statement that the conditions are not shielded. Removed 02Q .0504 from the regulations table.
--	--	52	2.2 B.1.b	Added condition for the approved AQAB review memo for the natural gas co-firing project for permit 03676/T57.
58	2.2 C	--	--	Removed this requirement to file an amended application for completion of the two-step significant modification process within one year from operation of the Natural Gas Co-firing Project.
63	2.4 D	57	2.4 D	Revised the Acid Rain Permit Application date.
--	Insignificant Activities List	58	3	Created this new section for insignificant activities. Removed I-13.
64	3	60	4	Created this new section and moved General Conditions to this section. Updated General Conditions to version 6.0, dated 01/07/2022.

IV. Permit History Since Last Renewal

August 4, 2917	Permit No. 03676T54 (Applications 1800073.13B, .14E, .15C, .16A and .16B) was issued for Title V and Title IV renewals.
August 22, 2017	Permit No. 03676T55 (Application 1800073.17) was a minor modification of a Title V permit to modify the method to be used as an indication of good operation and maintenance (Good O&M) for the PM continuous emission monitor systems (PM CEMS) under 02D .0606 in Section 2.1.A.7 of the permit.
December 20, 2018	Permit No. 03676T56 (Application 1800073.17A) was for construction and operation of a new flue gas desulfurization (FGD) wastewater treatment system (bioreactor), using the first step of the two-step Title V process pursuant to rule 02Q .0501(b)(2), to comply with the North Carolina Coal Ash Management Act (NC-CAMA) and EPA's Coal Combustion Residual (CCR) regulations.
May 3, 2019	Permit No. 03676T57 (Application 1800073.18B) was to add natural gas co-firing capability to Units 1 through 4 using the first step of the two-step Title V process pursuant to rule 02Q .0501(b)(2). As part of the project, Piedmont Natural Gas (PNG) will also install three 7 million British thermal units per hour (mmBtu/hr) natural gas heaters on the new natural gas supply line.
May 4, 2021	Permit No. 03676T58 (Application 1800073.20A) was the second step of the two-step Title V 02Q .0501(b)(2) Part II process for the FGD wastewater treatment facility permitted in Permit No. 03676T56.
TBD	Permit No. 03676T59 is being issued to renew the Title V and Title IV permits for five years and for the second step of the two-step Title V 02Q .0501(b)(2) Part II process for the natural gas co-firing project for Units 1 through 4 permitted in Permit No. 03676T57.

V. Regulatory Evaluation

The facility is subject to the following source-by-source regulations, in addition to the requirements in the General Conditions:

A. One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-1) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-1c (U1SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-2), electrostatic precipitator (ID No. CD-3), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U1/2FGD)

One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-2) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-4c (U2SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-5), electrostatic precipitator (ID No. CD-6), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U1/2FGD)

One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-3) and associated selective catalytic reduction system (SCR) NOx reduction system (ID No. CD-7c (SCR)), electrostatic precipitator (ID No. CD-9 (ESPnew)), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U3FGD)

One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-4) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-11c (U4SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-12), powdered activated carbon system (ID No. CD-U4ActC), electrostatic precipitator (ID No. CD-13 (ESPnew)), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U4FGD)

1. 15A NCAC 02D .0501(e): COMPLIANCE WITH EMISSION CONTROL STANDARDS
In addition to any control or manner of operation necessary to meet emission standards in 15A NCAC 02D .0500, any source of air pollution shall be operated with such control or in such manner that the source shall not cause the ambient air quality standards of 15A NCAC 02D .0400 to be exceeded at any point beyond the premises on which the source is located. When controls more stringent than named in the applicable emission standards in 15A NCAC 02D .0500 are required to prevent violation of the ambient air quality standards or are required to create an offset, the permit shall contain a condition requiring these controls.

   Emissions of sulfur dioxide from these sources shall not exceed 0.56 pounds per million Btu heat input in accordance with the permit application of September 22, 2003, and modeling analysis of October 29, 2003. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

   Monitoring/Recordkeeping
   The Permittee shall ensure compliance with 15A NCAC 02D .0501(e) by determining sulfur dioxide emissions in pounds per million Btu using continuous emissions monitoring (CEM) systems meeting the requirements of 40 CFR Part 75 except that unbiased values may be used (missing data shall be filled in accordance with 40 CFR Part 75). Compliance with sulfur dioxide emission standards shall be determined by averaging hourly continuous emission monitoring system values over a 24-hour block period beginning at midnight. To compute the 24-hour block average, the average hourly values (missing data shall be filled in accordance with 40 CFR Part 75) shall be summed, and the sum shall be divided by 24. The minimum number of data points, equally spaced, required to determine a valid hour value shall be determined by 40 CFR Part 75.

Reporting
The Permittee shall submit quarterly continuous emissions monitoring data showing the 24-hour daily block values in pounds per million Btu for each 24-hour daily block averaging period during the reporting period.

CEMs Availability - The Permittee shall submit sulfur dioxide CEM systems monitor downtime reports, including monitor availability values (as calculated for 40 CFR Part 75) for the last hour of the reporting period.

2. 15A NCAC 02D .0519: CONTROL OF NITROGEN OXIDES EMISSIONS
Emissions of nitrogen oxides from these sources when burning coal and oil (No. 2 fuel oil or recycled No.2 fuel oil) shall be calculated by the following equation:

$$E = \frac{(E_C)(Q_C)+(E_O)(Q_O)}{Q_t}$$

Where:

E	=	emission limit for combined burning of coal and oil in pounds per million Btu heat input
Ec	=	1.8 pounds per million Btu heat input for coal only
Eo	=	0.8 pounds per million Btu heat input for oil only
Qc	=	coal heat input in Btu per hour
Qo	=	oil heat input in Btu per hour
Qt	=	Qc + Qo

Monitoring
The Permittee shall ensure compliance with 15A NCAC 02D .0519 by determining nitrogen oxide emissions in pounds per million Btu using a continuous emissions monitoring (CEM) system meeting the requirements of 40 CFR Part 75 except that unbiased values may be used (missing data shall be filled in accordance with 40 CFR Part 75 whenever the unit combusts any fuel).

Recordkeeping
The Permittee shall maintain records of monthly coal and gas consumption (written or electronic form) and shall submit such records within 30 days of a request by DAQ.

Reporting
The Permittee shall submit the continuous emissions monitoring system data showing the 24-hour daily block values for periods of excess nitrogen oxide emissions semi-annually.

3. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
The permit condition for 15A NCAC 02D .0521 previously had two mutually exclusive options for monitoring, recordkeeping and reporting using either COMS or PM CEMS. The CEMS option was added several years ago when the facility began using PM CEMS for PM monitoring but wanted to retain the use of COMS in case problems arose with using CEMS. Now, since a PM CEMS is required by the MATS rule and COMS have not been used for several years, DEC agreed in an email on February 2, 2022 (see Chronology), that the COMS option can be removed.

Emission Limits
Visible emissions shall not be more than 40 percent opacity when averaged over a six-minute period.

Monitoring/Recordkeeping/Reporting
No monitoring/recordkeeping/reporting is required to demonstrate compliance with 15A NCAC 02D .0521.

4. 15A NCAC 02D .0536: PARTICULATE EMISSIONS FROM ELECTRIC UTILITY BOILERS
and
15A NCAC 02D .0536: ANNUAL AVERAGE OPACITY FOR ELECTRIC UTILITY BOILERS
As stated above, since regulation 15A NCAC 02D .0536 was repealed effective November 1, 2020, DEC has requested the removal of these sections of 02D .0536 that are no longer applicable.

5. <u>15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING for</u>
<u>15A NCAC 02D .0536: PARTICULATE EMISSIONS FROM ELECTRIC UTILITY BOILERS</u>
This regulation has been removed since it was used for compliance with the particulate emissions limit when previously using the COMS option under 15A NCAC 02D .0536, which is now being removed as discussed in Section V.A.4 above, and therefore 02D .0614 no longer applies. In addition, with removal of the PM COMS option, PM emissions monitoring now in Section 2.1 A.18 under 02D .0503 (see Section V.A.15 below) is now demonstrated with PM CEMS only, which is a continuous compliance determination method (CCDM) exemption under CAM.

6. <u>15A NCAC 02D .0535: EXCESS EMISSIONS REPORTING AND MALFUNCTIONS</u>
Along with removal of the 02D .0536 rules above, since the affected units are subject to the MACT standards in 40 CFR Part 63 Subpart UUUUU (i.e., the MATS rule) under 02D .1111, the provisions of 02D .0535 no longer apply as previously specified in 02D .0536 and as required for all electric utility boiler units as specified in 15A NCAC 02D .0535(d). Therefore, all references to a Malfunction Abatement Plan are being removed from the permit.

7. <u>15A NCAC 02D .0606: SOURCES COVERED BY APPENDIX P OF 40 CFR PART 51 (SULFUR DIOXIDE MONITORING, CONTINUOUS OPACITY MONITORING, AND EXCESS EMISSIONS)</u>
The permit condition for 15A NCAC 02D .0606 previously had two mutually exclusive options for monitoring, recordkeeping and reporting using either COMS or PM CEMS. The CEMS option was added several years ago when the facility began using PM CEMS for PM monitoring but wanted to retain the use of COMS in case problems arose with using CEMS. Now, since a PM CEMS is required by the MATS rule and COMS have not been used for several years, DEC agreed in an email on February 2, 2022 (see Chronology), that the COMS option can be removed.

<u>Monitoring/Recordkeeping</u>
The alternative monitoring and recordkeeping procedure in this section (Section 2.1 A.7.b) applies as allowed by Paragraph 3.9 of Appendix P of 40 CFR Part 51. The Permittee shall install, certify, operate, and maintain a PM CEMS to monitor and record PM emissions according to the applicable Maximum Achievable Control Technology (MACT) standards in 40 CFR 63.10010(i), as specified in Section 2.1 A.11.ff.

The quarterly excess emissions (EE) reports shall be used as an indication of good operation and maintenance of the electrostatic precipitators. These sources shall be deemed to be properly operated and maintained if the percentage of time the PM emissions, calculated on a one-hour average, greater than 0.030 pounds per million Btu heat input* does not exceed 3.0 percent of the total operating time for any given calendar quarter, adjusted for monitor downtime (MD) as calculated in below, except that Total Excess Emission Time contains all one-hour periods greater than 0.030 pounds per million Btu heat input*. In addition, these sources shall be deemed to be properly operated and maintained if the %MD does not exceed 2 percent for any given calendar quarter as calculated below.

> * The PM monitored value subject to the 0.030 pounds per million Btu limit shall have a 5% CO_2 diluent cap, or a 14% O_2 diluent cap, substituted in the emission rate calculation for a startup or shutdown hour in which the measured CO_2 concentration is below 5% or whenever the measured O_2 concentration is above 14%.

<u>Calculations for %EE and %MD</u>

<u>Percent Excess Opacity Emission (%EE) Calculation</u>:

$$\%EE = \frac{Total\ \ Excess\ Emission\ Time*}{Total\ \ Source\ Operating\ Time *** - Monitor\ \ Downtime}\ x100$$

<u>Percent Monitor Downtime (%MD) Calculation:</u>

$$\%MD = \frac{Total\ \ Monitor\ \ Downtime\ **}{Total\ \ Source\ \ Operating\ \ Time\ ***}\ x\,100$$

* Total Excess Emission Time contains any one-hour period greater than 0.030 pounds per million Btu heat input of PM emissions, including startup, shutdown, and malfunction.

** Total Monitor Downtime includes Quality Assurance (QA) activities unless exempted by regulation or defined in an agency approved QA Manual. The amount of exempt QA Time will be reported in the quarterly report as such.

*** Total Source Operating Time is the number of hours in a calendar quarter that the emission source operates.

The Permittee shall use a continuous emissions monitoring system (CEMS) to monitor and record sulfur dioxide emissions. Continuous emissions monitoring and recordkeeping of sulfur dioxide emissions shall be performed as described in Paragraphs 2 and 3.1.1 through 3.1.5 of Appendix P of 40 CFR Part 51. The monitoring systems shall meet the minimum specifications described in Paragraphs 3.3 through 3.8 of Appendix P of 40 CFR Part 51. If the emission unit is also subject to 40 CFR Part 75, then facility may follow the Quality Assurance and Quality Control (QA/QC) procedures in Appendix B to Part 75 in lieu of the 40 CFR Part 51 QA/QC procedures.

The quarterly excess emissions (EE) reports required under Appendix P of 40 CFR Part 51 shall be used as an indication of good operation and maintenance of the flue gas desulfurization scrubbers. These sources shall be deemed to be properly operated and maintained if sulfur dioxide emissions do not exceed 1.02 pounds per million Btu calculated on a 24-hour basis. Compliance with the sulfur dioxide emission standard is determined by averaging hourly continuous emission monitoring system values over a 24-hour block period beginning at midnight. To compute the 24-hour block average, the average hourly values are summed, and the sum is divided by 24. A minimum of four data points, equally spaced, is required to determine a valid hour value unless the continuous emission monitoring system is installed to meet the provisions of 40 CFR Part 75. If a continuous emission monitoring system is installed to meet the provisions of 40 CFR Part 75, the minimum number of data points is determined by 40 CFR Part 75. In addition, the flue gas desulfurization scrubbers shall be deemed to be properly operated and maintained if the %MD does not exceed 2 percent for any given calendar quarter as calculated above.

<u>Reporting</u>

The Permittee shall submit the excess emissions and monitor downtime reports as required under Appendix P of 40 CFR Part 51 postmarked on or before January 30 of each calendar year for the preceding three-month period between October and December, April 30 of each calendar year for the preceding three-month period between January and March, July 30 of each calendar year for the preceding three-month period between April and June, and October 30 of each calendar year for the preceding three-month period between July and September as shown below. Reporting shall be in accordance with Paragraphs 4 and 5.1 of Appendix P of 40 CFR Part 51.

a. Excess PM emissions are defined as any one-hour average greater than 0.030 pounds per million Btu heat input. The quarterly report shall include the number of hours each day and the percent of operating hours during the quarter with average PM emissions recorded by the PM CEMS greater than 0.030 pounds per million Btu including the application of any applicable diluent caps during a startup or shutdown hour.
b. For sulfur dioxide, excess emissions are defined as greater than 1.02 pounds per million Btu calculated on a 24-hour block average basis.
c. All instances of deviations from the requirements of this permit must be clearly identified.

8. CROSS STATE AIR POLLUTION RULES (CSAPR) PERMIT REQUIREMENTS
For the four boilers (ID Nos. ES-1 thru ES-4), the Permittee shall comply with all applicable requirements of 40 CFR Part 97, Subpart AAAAA "CSAPR NOx Annual Trading Program" and Subpart CCCCC "CSAPR SO2 Group 1 Trading Program".

9. 15A NCAC 02Q .0317: AVOIDANCE CONDITIONS FOR
15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
This condition was added to Permit No. 03676T47 on September 14, 2010, for PM/PM10.

In order to avoid applicability of 15A NCAC 02D .0530(g), the PM/PM10 emissions from the Unit 4 boiler (ID No. ES-4) shall be less than 15 tons per consecutive 12-month period, attributable to injecting powdered activated carbon.

Monitoring/Recordkeeping
The amount of injected powdered activated carbon in Unit 4 boiler (ID No. ES-4) shall not exceed 9,000,000 lbs per year. The Permittee shall keep monthly records of the amount of powered activated carbon injected.

Reporting
The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall contain the monthly amount of powdered activated carbon injected in the Unit 4 boiler for the previous 17 months.

10. 15A NCAC 02Q .0317: AVOIDANCE CONDITIONS FOR
15A NCAC 02D .0531: SOURCES IN NONATTAINMENT AREAS
This condition was added to Permit No. 03676T47 on September 14, 2010, for PM2.5.

In order to avoid applicability of 15A NCAC 02D .0531(f), the PM2.5 emissions from the Unit 4 boiler (ID No. ES-4) shall be less than 10 tons per consecutive 12-month period, attributable to injecting powdered activated carbon.

Monitoring/Recordkeeping/Reporting
The monitoring/recordkeeping/reporting requirements in Section V.A.9 above shall be sufficient to ensure compliance with 15A NCAC 02D .0531.

11. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR PART 63, SUBPART UUUUU)
The Subpart UUUUU requirements were added to permit 03676T53 on February 10, 2017.
Each of the Electric Generating Units are subject to all applicable requirements pertaining to existing, coal-fired EGUs with heating value greater than or equal to 8,300 Btu/lb.

In accordance with 40 CFR 63.9984(b), the EGUs are required to comply with all applicable requirements of Subpart UUUUU by no later than April 16, 2015. However, the DAQ granted a 1-year extension in accordance with 40 CFR 63.6(i)(4)(i)(A), for complying with the applicable standards under the regulation until April 16, 2016.

Emission Limitations
The following limits apply:

a. i. limit the emissions of filterable particulate matter (PM) to 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh; or
   ii. limit the emissions of total non-Hg HAP metals to 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh; or
   iii. limit the emissions of individual HAP metals to:

Constituent	Allowable Level
Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh
Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh
Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh
Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh
Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh
Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh
Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh
Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh
Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh
Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh

b. i. limit the emissions of hydrogen chloride (HCl) to 2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh; or
   ii. limit the emissions of sulfur dioxide (SO_2) to 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.

c. limit the emissions of mercury (Hg) to 1.2E0 lb/TBtu or 1.3E-2 lb/GWh.

The Marshall facility has chosen to comply with the MATS rule by limiting emission as follows:

a. filterable particulate matter (PM) to 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh (using PM CEMS),
b. sulfur dioxide (SO2) to 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh (using SO2 CEMS), and
c. mercury (Hg) to 1.2E0 lb/TBtu or 1.3E-2 lb/GWh (using Hg CEMS and/or sorbent trap(s)).

12. <u>15A NCAC 02D .0530(u): USE OF PROJECTED ACTUAL EMISSIONS TO AVOID APPLICABILITY OF PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS</u>

<u>Monitoring/Recordkeeping/Reporting</u>
The Permittee has used projected actual emissions to avoid applicability of prevention of significant deterioration requirements, pursuant to Application 1800073.18B, for the natural gas co-firing project in Permit No. 03676T57. The Permittee shall perform the following:

a. The Permittee shall maintain records of annual emissions in tons per year, on a calendar year basis related to the natural gas co-firing project, for five years following resumption of regular operations after the change is made.
b. The Permittee shall submit a report to the Director within 60 days after the end of each calendar year during which these records must be generated. The report shall contain the items listed in 40 CFR 51.166(r)(6)(v)(a) through (c).
c. The Permittee shall make the information documented and maintained under this condition available to the Director or the general public pursuant to the requirements in 40 CFR 70.4(b)(3)(viii).
d. The reported actual emissions (post-construction emissions) for each of the five calendar years will be compared to the projected actual emissions (pre-construction projection) as included below:

Regulated NSR Pollutant	**Projected Actual Emissions* (tons per year)**		
	Unit 1 and Unit 2 (ES-1 and ES-2)	**Unit 3 (ES-3)**	**Unit 4 (ES-4)**
NOx (as NO_2)	2,484.7	2,720.1	3,624.2
PM (filterable)	46.5	40.3	59.1
PM_{10}	65.8	70.5	81.6
$PM_{2.5}$	51.8	61.6	66.7
SO_2	1,031.3	1,686.4	1,587.7
VOC	24.7	57.7	57.1

Regulated NSR Pollutant	Projected Actual Emissions* (tons per year)		
	Unit 1 and Unit 2 (ES-1 and ES-2)	**Unit 3 (ES-3)**	**Unit 4 (ES-4)**
CO	840.1	1,250.4	2,920.3
HF	1.52	1.22	1.26
Lead	1.16E-02	8.51E-03	1.23E-02
Sulfuric Acid Mist	45.4	49.2	31.5
GHG as CO_{2e}	1,830,903	2,331,659	2,357,423

* These projections are not enforceable limitations. If projected emissions are exceeded, consistent with 15A NCAC 02D .0530, the Permittee shall include in its annual report an explanation as to why the actual rates exceeded the projection.

13. <u>15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT</u>
This requirement in Section 2.2 C.1 of the permit, for completion of the two-step significant modification process initiated by Application No. 1800073.18B (added in Permit No. 03676T57) for the natural gas co-firing project, to file the Part II application within one year from beginning to burn natural gas; is removed since the current application 1800073.21A satisfies that requirement.

14. <u>15A NCAC 02Q .0402 ACID RAIN PERMITTING PROCEDURES (40 CFR Part 72) Phase II Acid Rain Permit Requirements</u>
DEC submitted a renewal Acid Rain Permit Application 1800073.22B, received January 28, 2022, for renewal of the acid rain permit for the four coal-fired boilers (ID Nos. ES-1 through ES-4).

The effective dates of the acid rain portion of the permit are the same as the Title V permit itself. The Acid Rain Permit Application dated January 19, 2022 will become part of the Title V permit (as an attachment).

The applicable acid rain rules for these sources, as specified in the Acid Rain Permit Application includes the following emission and monitoring requirements:

<u>15A NCAC 02Q .0402 Acid Rain Procedures (40 CFR Part 72 Permits Regulation)</u>
North Carolina air quality regulation 15A NCAC 02Q .0400 implements Phase II of the federal acid rain program pursuant to Title IV of the CAA as provided in 40 CFR Part 72. Issuance or denial of acid rain permits shall follow the procedures under 40 CFR Part 70 (Title V) and Part 72. If the provisions or requirements of Part 72 conflict with or are not included in Part 70, the Part 72 provisions and requirements shall apply and take precedence.

<u>15A NCAC 2Q .0400 “Acid Rain Procedures” (40 CFR Part 73 “Sulfur Dioxide Allowance System”)</u>
Establishes the procedures for allocation, tracking, holding and transfer of sulfur dioxide emission allowances, including the initial allowances allocated to each applicable Phase II unit account to be held in calendar years 2010 and each year thereafter (Table 2, column F).

<u>15A NCAC 2Q .0400 “Acid Rain Procedures” (40 CFR Part 76 “Acid Rain Nitrogen Oxides Emission Reduction Program”)</u>
Each coal-fired utility unit that is subject to an Acid Rain emissions limit for SO_2 under Phase I or Phase II of the CAA must meet the NOx emission limitations under 40 CFR Part 76 in compliance with 40 CFR 76.5, 76.6 or 76.7, as shown in the application. DEC has a Phase II NOx Compliance Plan and a Phase II NOx Averaging Plan both dated June 23, 2015, for the coal fired units at their six facilities, with the Marshall boilers subject to the annual average alternative contemporaneous emission limitation and annual heat input limits as shown in the Averaging Plan and in Section 2.5 of the permit.

15A NCAC 02Q .0402 Acid Rain Procedures (40 CFR Part 75 Continuous Emissions Monitoring)
This regulation establishes requirements for the installation, certification, operation, and maintenance of continuous emissions or opacity monitoring systems.

15. 15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
Since regulation 15A NCAC 02D .0536 was repealed effective November 1, 2020, it is being removed. In its place, the 02D .0503 particulate emission rule is being added to the permit as recommended in a memorandum dated October 11, 2019, from Dennis Igboko, Stationary Source Compliance Branch.

Emissions of particulate matter from the boilers shall not exceed 0.081 pounds per million Btu heat input as calculated below.

This rule applies to installations burning fuel, including natural gas and fuel oils, for the purpose of producing heat or power by indirect heat transfer. For the purpose of this rule, the maximum heat input shall be the total heat content of all fuels which are burned in a fuel burning indirect heat exchanger, of which the combustion products are emitted through a stack or stacks. The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger. Fuel burning indirect heat exchangers constructed or permitted after February 1, 1983, shall not change the allowable emission limit of any fuel burning indirect heat exchanger whose allowable emission limit has previously been set. The removal of a fuel burning indirect heat exchanger shall not change the allowable emission limit of any fuel burning indirect heat exchanger whose allowable emission limit has previously been established. However, for any fuel burning indirect heat exchanger constructed after, or in conjunction with, the removal of another fuel burning indirect heat exchanger at the plant site, the maximum heat input of the removed fuel burning indirect heat exchanger shall no longer be considered in the determination of the allowable emission limit of any fuel burning indirect heat exchanger constructed after or in conjunction with the removal. The emission rate for these sources is determined below.

The facility-wide heat inputs will be as follows:

Source	Heat Input (mmBtu/hr)
Boiler ES-1 (existing)	4,230
Boiler ES-2 (existing)	4,230
Boiler ES-3 (existing)	7,110
Boiler ES-4 (existing)	7,110
ES-HTR1 natural gas supply line heater (new)	7
ES-HTR2 natural gas supply line heater (new)	7
ES-HTR3 natural gas supply line heater (new)	7
Total	22,701

Allowable emissions of particulate matter from fuel combustion shall be calculated as follows:

$$E = 1.090\ Q^{-0.2594}$$

where: E = allowable particulate emission rate, pounds per million Btu
Q = maximum heat input rate (total at plant site), million Btu per hour

Therefore, emissions of particulate matter from the boilers shall not exceed the following:

$$\begin{aligned} E &= 1.090\ Q^{-0.2594} \\ &= 1.090\ (22{,}701)^{-.2594} \\ &= 0.081 \text{ lb/mmBtu} \end{aligned}$$

Streamlining the 02D .0503 condition with MATS
As allowed under 40 CFR 70.6(a)(3)(i)(A):

"If more than one monitoring or testing requirement applies, the permit may specify a streamlined set of monitoring or testing provisions provided the specified monitoring or testing is adequate to assure compliance at least to the same extent as the monitoring or testing applicable requirements that are not included in the permit as a result of such streamlining."

The monitoring (including recordkeeping) for the MATS requirements in Section 2.1 A.16 of the permit is adequate to ensure compliance at least to the same extent as required for the 02D .0503 monitoring requirements in Section 2.1 A.18; therefore, streamlining is specified for compliance. The 0.030 pounds per million Btu heat input PM limit for MATS compliance is much more stringent than the 0.081 pounds per million Btu heat input PSD avoidance PM limit.

<u>Monitoring/Recordkeeping</u>
The monitoring and recordkeeping requirements in Sections 2.1 A.16.ff and ii of the permit shall satisfy the requirements of this section. A measured exceedance of 0.030 pounds per million Btu heat input (30-boiler operating day rolling average) or 0.30 pounds per megawatt hour (30-boiler operating day rolling average) shall be a violation of the corresponding emission standards in Section 2.1 A.18.a.

<u>Reporting</u>
The Permittee shall submit quarterly excess emissions and monitoring system performance reports. The compliance report shall include, at a minimum, the information required in 40 CFR 63.10 and contain the information specified in Section 2.1 A.16.xx of the permit, along with all 30-boiler operating day rolling average excess emissions (pounds per million Btu or pounds per megawatt hour) using the CEMS outlet data, including periods exempted during periods of startup and shutdown. The PM CEMS data submitted for compliance with 40 CFR Part 63 Subpart UUUUU can be used to satisfy the requirement of this section.

B. Limestone Receiving, Transfer, Storage, and Processing Equipment:
Limestone train unloading facility (ID No. ES-6 (RUL)),
Two limestone rail unloading hoppers (ID Nos. ES-6a (RULa) and ES-6b (RULb)),
60 inches wide limestone unloading belt feeder no. A (ID No. ES-7 (LUBFA)),
60 inches wide limestone unloading belt feeder no. B (ID No. ES-8 (LUBFB)), and
associated baghouse (ID No. CD-RULBF),

48 inches wide limestone unloading conveyor (ID No. ES-9 (LCB1)),
48 inches wide limestone stack out conveyor (ID No. ES-11 (LCB2)),
40 inches wide limestone reclaim grate feeder (ID No. ES-12a (LPR)),
30 inches wide limestone reclaim conveyor (ID No. ES-12b (LCB3)),
30 inches wide limestone plant feed conveyor no. 1 (ID No. ES-14 (LCB4)),
30 inches wide limestone plant feed conveyor no. 2 (ID No. ES-16 (LCB5)),
30 inches wide limestone plant feed conveyor no. 3 (ID No. ES-18a (LCB6a)),
36 inches wide emergency limestone feeder conveyor (ID No. ES-18c (LCB6c)),
Limestone wet ball mill no. 1 (ID No. ES-24 (BM1)), and
Limestone wet ball mill no. 2 (ID No. ES-25 (BM2)),

Emergency limestone bucket elevator (ID No. ES-18b (ELBE)),
30 inches wide limestone silo fill conveyor no. 1 (ID No. ES-20 (S1LCB7)),
30 inches wide limestone silo fill conveyor no. 2 (ID No. ES-21 (S2LCB8)),
Limestone storage silo no. 1 (ID No. ES22 (LS1)),
Limestone storage silo no. 2 (ID No. ES23 (LS2)), and
associated baghouse (ID No. CD-LPTTBF)

1. 15A NCAC 02D .0510: PARTICULATES FROM SAND, GRAVEL, OR CRUSHED STONE OPERATIONS

   The Permittee shall not cause, allow, or permit any material in a sand, gravel, or crushed stone operation to be produced, handled, transported or stockpiled without taking measures to reduce to a minimum any particulate matter from becoming airborne to prevent exceeding the ambient air quality standards beyond the property line for particulate matter, both PM10 and total suspended particulates.

   Fugitive non-process dust emissions from sand, gravel, or crushed stone operations shall be regulated by 15A NCAC 02D .0540 below.

   The Permittee shall control process-generated emissions from conveyors, screens, and transfer points, such that the applicable opacity standards in Sections V.B.3 and 4 below are not exceeded.

   Monitoring/Recordkeeping/Reporting
   The monitoring/recordkeeping/reporting required in Sections V.B.4 below for particulate matter is sufficient to ensure compliance with 15A NCAC 02D .0510.

2. 15A NCAC 02D .0540: PARTICULATES FROM FUGITIVE NON-PROCESS DUST EMISSION SOURCES

   a. The Permittee shall not cause or allow fugitive non-process dust emissions (i.e., particulate matter that is not collected by a capture system and is generated from areas such as pit areas, process areas, haul roads, stockpiles, and plant roads) to cause or contribute to substantive complaints (i.e., complaints that are verified with physical evidence acceptable to the DAQ).
   b. If fugitive non-process dust emissions cause or contribute to substantive complaints, the Permittee shall:
      i. Within 30 days upon receipt of written notification from the Director of a second substantive complaint in a 12-month period, submit to the Director a written description of what has been done and what will be done to reduce fugitive non-process dust emissions from that part of the facility that caused the second substantive complaint;
      ii. Within 90 days of receipt of written notification from the Director of a second substantive complaint in a 12-month period, submit to the Director a control plan; and
      iii. Within 30 days after the Director approves the plan, be in compliance with the plan.
   c. The Director may require that the Permittee develop and submit a fugitive non-process dust control plan if:
      i. Ambient air quality measurements or dispersion modeling acceptable to the DAQ show violation or a potential for a violation of an ambient air quality standard for particulates in 15A NCAC 02D .0400 “Ambient Air Quality Standards;” or
      ii. If the DAQ observes excessive fugitive non-process dust emissions from the facility beyond the property boundaries.
      The control plan shall be submitted to the Director no later than 90 days after notification. The facility shall be in compliance with the plan within 30 days after the Director approves the plan.
   d. A fugitive dust control plan shall:
      i. Identify the sources of fugitive non-process dust emissions within the facility;
      ii. Describe how fugitive non-process dust will be controlled from each identified source;
      iii. Contain a schedule by which the plan will be implemented;
      iv. Describe how the plan will be implemented, including training of facility personnel; and
      v. Describe methods to verify compliance with the plan.
   e. The Director shall approve the plan if he finds that:
      i. The plan contains all required elements;
      ii. The proposed schedule contained in the plan will reduce fugitive non-process dust emissions in a timely manner;
      iii. The methods used to control fugitive non-process dust emissions are sufficient to prevent fugitive non-process dust emissions from causing or contributing to a violation of the ambient air quality standards for particulates; and
      iv. The described compliance verification methods are sufficient to verify compliance with the plan.

If the Director finds that the proposed plan does not meet the requirements, he shall notify the Permittee of any deficiencies in the proposed plan. The Permittee shall have 30 days after receiving written notification from the Director to correct the deficiencies.

f. If after a plan has been implemented, the Director finds that the plan inadequately controls fugitive non-process dust emissions; he shall require the Permittee to correct the deficiencies in the plan. Within 90 days after receiving written notification from the Director identifying the deficiency, the Permittee shall submit a revision to his plan to correct the deficiencies.

3. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Emission Limit

Visible emissions from limestone rail unloading station (ID No. ES-6 (RUL)) shall not be more than 20 percent opacity when averaged over a six-minute period.

Monitoring

To ensure compliance, once a month the Permittee shall observe the emissions from the limestone rail unloading station (ID No. ES-6 (RUL)) for any visible emissions above normal. If visible emissions from this source are observed to be above normal, the Permittee shall either: (a) immediately shutdown the source and repair the malfunction, (b) be deemed to be in noncompliance with 15A NCAC 02D .0521 or (c) demonstrate that the percent opacity from the emission points of the emission sources in accordance with 15A NCAC 02D .2610 for 30 minutes is below the limit given above. If the demonstration in (c) above cannot be made, the Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521.

Recordkeeping

The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

i. The date and time of each recorded action;
ii. The results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
iii. The results of any corrective actions performed.

Reporting

The Permittee shall submit a semi-annual summary report of the observations.

4. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS

New Source Performance Standards (NSPS) as promulgated in 40 CFR Part 60 Subpart OOO "Standards of Performance for Nonmetallic Mineral Processing Plants."

Emission Limits

a. On and after the date on which the performance test is completed, the Permittee shall not allow to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any stack emissions that:
    i. Contain particulate matter in excess of 0.05 g/dscm (0.022 gr/dscf); and
    ii. Exhibit greater than 7 percent opacity.
    iii. Emission sources with stack emissions affected by these requirements include:
        (A) Railcar unloading enclosure dust collection system with fabric filter (ID No. CD-RULBF) installed on: two limestone rail unloading hoppers (ID Nos. ES-6a (RULa) and ES-6b (RULb)), 60 inches wide limestone unloading belt feeder no. A (ID No. ES-7 (LUBFA)), 60 inches wide limestone unloading belt feeder no. B (ID No. ES-8 (LUBFB));
        (B) Limestone plant dust collection system with fabric filter (ID No. CD-LPTTBF) installed on: emergency limestone bucket elevator (ID No. ES-18b (ELBE)), 30 inches wide limestone silo fill conveyor no. 1 (ID No. ES-20 (S1LCB7)), 30 inches wide limestone silo fill conveyor no. 2 (ID No. ES-21 (S2LCB8)), limestone storage silo no. 1 (ID No. ES22 (LS1)), limestone storage silo no. 2 (ID No. ES23 (LS2)); and

(C) Any vent as defined in 40 CFR 60.671 of any building enclosing any affected emission source.

b. On and after the date on which the performance test is completed, the Permittee shall not allow to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility, fugitive emissions that exhibit greater than 10 percent opacity. Where any transfer points on belt conveyors or any other affected facility are enclosed inside a building, the Permittee may choose to comply with the emission standard requirements for building enclosures as defined below under Section V.B.4.d below instead.

c. On and after the date on which the performance test is completed, the Permittee shall not allow to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions that exhibit greater than 15 percent opacity. Affected sources include the two limestone wet ball mills (**ID Nos. ES-24(BM1)** and **ES-25(BM2)**) located inside the reagent preparation building. Since the affected sources are enclosed inside a building, the Permittee may choose to comply with the emission standard requirements for building enclosures as defined below under Section V.B.4.d below instead.

d. In lieu of meeting the requirements of Sections V.B.4.b and c above for NSPS-affected emissions sources enclosed inside a building, the Permittee may choose to comply with the following requirements:
   i. Fugitive emissions from the building openings (except for vents as defined in 40 CFR 60.671) shall not exceed 7 percent opacity;
   ii. Any vent as defined in 40 CFR 60.671 on any building enclosing any transfer point on a conveyor belt or any other affected facility shall not discharge emissions of particulate matter in excess of 0.05 g/dscm (0.022 gr/dscf) or visible emissions in excess of 7 percent opacity.
   iii. Affected buildings include the limestone unloading transfer tower which houses the transfer point between ES-9 (LCB1) and ES-11 (LCB2), transfer tower #1 which houses the transfer point between ES-12b (LCB3) and ES-14 (LCB4), the yard transfer tower which houses the transfer point between ES-14 (LCB4) and ES-16 (LCB5), transfer tower #2 which houses the transfer point between ES-16 (LCB5) and ES-18a (LCB6a), the limestone plant transfer tower which houses the transfer point between ES-18c (LCB6c) and ES-18b (ELBE), and the reagent preparation building which houses ES-24 (BM1) and ES-25 (BM2).

<u>Monitoring</u>
Particulate matter emissions from sources ID Nos. ES-6a (RULa), ES-6b (RULb), ES-7 (LUBFA), and ES-8 (LUBFB) shall be controlled by fabric filter ID No. CD-RULBF, and particulate matter emissions from sources ID Nos. ES-18b (ELBE), ES-20 (S1LCB7), ES-21 (S2LCB8), ES22 (LS1), and ES23 (LS2) shall be controlled by fabric filter ID No. CD-LPTTBF. To ensure compliance, the Permittee shall perform inspections and maintenance on the fabric filters as recommended by the manufacturer. In addition to the manufacturer's inspection and maintenance recommendations, or if there are no manufacturer's inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:
a. A monthly visual inspection of the system ductwork and baghouse for leaks; and
b. An annual internal inspection of the baghouse, fabric filters, and ducting for structural integrity for each 12- month period following the initial inspection.

To ensure compliance with the opacity standards, once a month the Permittee shall observe the individual NSPS-affected emission sources (ID Nos. ES-6a (RULa), ES-6b (RULb), ES-7 (LUBFA), ES-8 (LUBFB), ES-9 (LCB1), ES-11 (LCB2), ES-12a (LPR), ES-12b (LCB3), ES-14 (LCB4), ES-16 (LCB5), ES-18a (LCB6a), ES-18b (ELBE), 18c(LCB6c), ES-20 (S1LCB7), ES-21 (S2LCB8), ES22 (LS1), ES23 (LS2), ES-24 (BM1), and ES-25 (BM2)) subject to an opacity standard, or the buildings/enclosures housing these sources, for any visible emissions above normal. If visible emissions from these sources are observed to be above normal, the Permittee shall either:
a. immediately shutdown the source, repair the malfunction, and conduct a follow-up visible emissions observation demonstrating normal emissions,

b. be deemed to be in noncompliance with 15A NCAC 02D .0524, or
c. demonstrate that the percent opacity from the emission points of the emission sources in accordance with 40 CFR 60.675 and 15A NCAC 02D .2610 is below the limit given in Sections V.B.4.a.ii, b, and c above.

Recordkeeping

The results of all inspection and maintenance activities shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each inspection;
c. The results of any maintenance performed on the fabric filters, duct work, or baghouse; and
d. Any variance from manufacturer's recommendations, if any, and corrections made.

The results of the visible emission monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
c. The results of any corrective actions performed.

Reporting

The Permittee shall submit a semi-annual summary report of the monitoring and recordkeeping activities.

State-Only Requirement

5. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS

Emission Limits

In accordance with the approved application for a facility-wide air toxic compliance demonstration, the permit limits in Section 2.2 B.1 shall not be exceeded.

The Permittee has submitted a toxic air pollutant dispersion modeling analysis dated March 18, 2019, for the facility's toxic air pollutant emissions. The source limits were placed in Permit 03676/T57, issued May 3, 2019, for the natural gas co-firing project. The modeling analysis was reviewed and approved by the AQAB on April 18, 2019.

Monitoring/Recordkeeping/Reporting

There are no monitoring, recordkeeping, or reporting requirements.

C. One 1,000 HP, No. 2 fuel oil fired emergency use water pump (ID No. ES-26 (EQWP))

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

Emission Limit

Emissions of sulfur dioxide from the diesel generator shall not exceed 2.3 pounds of sulfur dioxide per million Btu heat input.

Monitoring/Recordkeeping/Reporting

No monitoring/recordkeeping/reporting is required for sulfur dioxide emissions from the firing of No. 2 fuel oil in this source.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Emission Limit

Visible emissions from this source shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period.

Monitoring
To ensure compliance, the Permittee shall perform a Method 9 test for 1 hour using a pre-approved protocol to be submitted in accordance with General Condition JJ before the sources operate more than 1,100 hours using No. 2 fuel oil.

Recordkeeping
The Permittee shall keep records of the hours and associated dates when these sources are in operation using No. 2 fuel oil, and the dates of performance of Method 9 tests.

Reporting
The Permittee shall submit quarterly results of any Method 9 test.

3. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (40 CFR PART 63, SUBPART ZZZZ)
Pursuant to 40 CFR 63.6590(b)(1)(i), this emergency RICE does not have to meet the requirements of 40 CFR 63 Subpart ZZZZ and Subpart A except for the initial notification requirements of 40 CFR 63.6645(f). These notification requirements were met in the submittal of permit application No. 1800073.03B.

D. One limestone storage pile (ID No. F1)

1. 15A NCAC 02D .0540: PARTICULATES FROM FUGITIVE NON-PROCESS DUST EMISSION SOURCES
See Section V.B.2 above.

State-Only Requirement
2. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
See Section V.B.5 above.

E. Two ash storage silos (ID Nos. ES-S1 and ES-S2),
two (dry) flyash truck loading equipment (ID Nos. ES-FTLD1 and ES-FTLD2), and associated baghouses (ID Nos. CD-S1 and CD-S2)
two (wet) flyash truck loading equipment (ID Nos. ES-FTLW1 and ES-FTLW2

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

Emission Limit
Emissions of particulate matter from these sources shall not exceed an allowable emission rate as calculated by the following equation:

$E = 4.10 \times P^{0.67}$ (for process rates less than or equal to 30 tons per hour), or
$E = 55.0 \times P^{0.11} - 40$ (for process rates greater than 30 tons per hour)

Where: E = allowable emission rate in pounds per hour
P = process weight in tons per hour

Monitoring/Recordkeeping
Particulate matter emissions from the two ash storage silos (ID Nos. ES-S1 and ES-S2) and two dry flyash truck loading equipment (ID Nos. ES-FTLD1 and ES-FTLD2) shall be controlled by the bagfilters (ID Nos. CD-S1 and CD-S2). To ensure compliance, the Permittee shall perform inspections and maintenance as recommended by the manufacturer. In addition to the manufacturer’s inspection and maintenance recommendations, or if there are no manufacturer’s inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:

a. A monthly visual inspection of the system ductwork and material collection unit for leaks; and

b. An annual (for each 12-month period following the initial inspection) internal inspection of the bagfilters' structural integrity.

The results of inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each inspection;
c. The results of any maintenance performed on the bagfilters; and
d. Any variance from manufacturer's recommendations, if any, and corrections made.

Reporting

The Permittee shall submit the results of any maintenance performed on the bagfilters within 30 days of a written request by the DAQ.

The Permittee shall submit a semi-annual summary report of the monitoring and recordkeeping activities shown above.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Emission Limit

Visible emissions from these sources shall not be more than 20 percent opacity when averaged over a six-minute period.

Monitoring

To ensure compliance, once a month the Permittee shall observe the emission points of these sources for any visible emissions above normal. If visible emissions from these sources are observed to be above normal, the Permittee shall either: (a) immediately shutdown the source and repair the malfunction, (b) be deemed to be in noncompliance with 15A NCAC 02D .0521 or (c) demonstrate that the percent opacity from the emission points of the emission sources in accordance with 15A NCAC 02D .2610 for 30 minutes is below the emission limit given above.

Recordkeeping

The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
c. The results of any corrective actions performed.

Reporting

The Permittee shall submit a semi-annual summary report of the observations.

State-Only Requirement

3. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS

See Section V.B.5 above.

F. Four NSPS coal conveyors (ID Nos. ES-CCONV2, ES-CCONV6, ES-CCONV7 and ES-CCONV8)

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

   Emission Limit
   Emissions of particulate matter from these sources shall not exceed an allowable emission rate as calculated by the following equation:

   $E = 4.10 \times P^{0.67}$ (for process rates less than or equal to 30 tons per hour), or
   $E = 55.0 \times P^{0.11} - 40$ (for process rates greater than 30 tons per hour)

   Where: E = allowable emission rate in pounds per hour
   P = process weight in tons per hour

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for particulate emissions from these sources to ensure compliance with this regulation.

2. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS
   New Source Performance Standards (NSPS) as promulgated in 40 CFR Part 60, Subpart Y "Standards of Performance for Coal Preparation and Processing Plants."

   Emission Limit
   On or after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, visible emissions shall not be 20 percent opacity or greater except during periods of startup, shutdown and malfunction.

   Monitoring
   To ensure compliance, once a month the Permittee shall observe the emission points of these sources for any visible emissions above normal. If visible emissions from this source are observed to be above normal, the Permittee shall either: (a) immediately shutdown the source and repair the malfunction, (b) be deemed to be in noncompliance with 15A NCAC 02D .0524 or (c) demonstrate that the percent opacity from the emission points of the emission source in accordance with 15A NCAC 02D .2610 for 30 minutes is below the emission limit given above.

   Recordkeeping
   The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   a. The date and time of each recorded action;
   b. The results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
   c. The results of any corrective actions performed.

   Reporting
   The Permittee shall submit a semi-annual summary report of the monitoring and recordkeeping activities.

   State-Only Requirement
3. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
   See Section V.B.5 above.

G. One No. 2 fuel oil-fired emergency/blackout protection diesel generator (ID No. ES-35 (EmGen)) and one No. 2 fuel oil-fired diesel emergency air compressor (ID No. ES-36 (AC))

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

   Emission Limit
   Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for sulfur dioxide emissions from the firing of No. 2 fuel oil in these sources.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

   Emission Limit
   Visible emissions from this source shall not be more than 20 percent opacity when averaged over a six-minute period.

   Monitoring
   To ensure compliance, the Permittee shall perform a Method 9 test for 1 hour using a preapproved protocol to be submitted in accordance with General Condition JJ before the sources operate more than 1100 hours using No. 2 fuel oil. This monitoring protocol shall be repeated before each subsequent 1100 hours of operation using No. 2 fuel oil from the last test for each source.

   Recordkeeping
   The Permittee shall keep records of the hours and associated dates, when these sources are in operation using No. 2 fuel oil, and the dates of performance of Method 9 tests.

   Reporting
   The Permittee shall submit quarterly results of any Method 9 test.

3. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
   Pursuant to 40 CFR 63.6590(b)(1)(i), this emergency RICE does not have to meet the requirements of 40 CFR 63 Subpart ZZZZ and Subpart A except for the initial notification requirements of 40 CFR 63.6645(f). These notification requirements were met in the submittal of permit application No. 1800073.04B.

H. One flyash transfer silo (ID No. ES-TSU3&4) and associated bagfilter (ID No. TSVF)

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

   Emission Limit
   Emissions of particulate matter from these sources shall not exceed an allowable emission rate as calculated by the following equation:

   $E = 4.10 \times P^{0.67}$ (for process rates less than or equal to 30 tons per hour), or
   $E = 55.0 \times P^{0.11} - 40$ (for process rates greater than 30 tons per hour)

   Where: E = allowable emission rate in pounds per hour
   P = process weight in tons per hour

Monitoring/Recordkeeping
Particulate matter emissions from the flyash transfer silo (ID No. ES-TSU3&4) shall be controlled by the bagfilter (ID No. CD-TSVF). To ensure compliance, the Permittee shall perform inspections and maintenance as recommended by the manufacturer. In addition to the manufacturer's inspection and maintenance recommendations, or if there are no manufacturer's inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:

a. A monthly visual inspection of the system ductwork and material collection unit for leaks; and
b. An annual (for each 12-month period following the initial inspection) internal inspection of the bagfilters' structural integrity.

The results of inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each inspection;
c. The results of any maintenance performed on the bagfilters; and
d. Any variance from manufacturer's recommendations, if any, and corrections made.

Reporting
The Permittee shall submit the results of any maintenance performed on the bagfilters within 30 days of a written request by the DAQ.

The Permittee shall submit a semi-annual summary report of the monitoring and recordkeeping activities.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Emission Limit
Visible emissions from this source shall not be more than 20 percent opacity when averaged over a six-minute period.

Monitoring
To ensure compliance, once a month the Permittee shall observe the emission points of these sources for any visible emissions above normal. If visible emissions from these sources are observed to be above normal, the Permittee shall either: (a) immediately shutdown the source and repair the malfunction, (b) be deemed to be in noncompliance with 15A NCAC 02D .0521 or (c) demonstrate that the percent opacity from the emission points of the emission sources in accordance with 15A NCAC 02D .2610 for 30 minutes is below the emission limit given above.

Recordkeeping
The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
c. The results of any corrective actions performed.

Reporting
The Permittee shall submit a summary report of the observations postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June.

State-Only Requirement

3. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
   See Section V.B.5 above.

I. One 100 kW No. 2 Fuel Oil-Fired Emergency Generator Located at Landfill (ID No. ES-37 (EmGenLF))

1. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

   Emission Limit
   Visible emissions from this source shall not be more than 20 percent opacity when averaged over a six-minute period.

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for visible emissions from the firing of No. 2 fuel oil in this source.

2. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS
   New Source Performance Standards (NSPS) as promulgated in 40 CFR Part 60 Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."

   Emission Limits
   In accordance with §60.4205(b) and §60.4202(a)(2), the following emissions standards shall apply for this generator:

AFFECTED SOURCE	POLLUTANT	EMISSION LIMIT (g/hp-hr)
emergency generator (ID No. ES-37 (EmGenLF))	nitrogen oxides + VOCs	4.0
	carbon monoxide	5.0
	PM	0.30

   Monitoring/Recordkeeping/Reporting

   a. For operation after October 1, 2010, the engine must use diesel fuel with sulfur content of less than 15 ppm.
   b. The engine must be equipped with a non-resettable hour meter prior to startup.
   c. If the emergency generator is equipped with diesel particulate filter to comply with the above emission standards, the Permittee shall install backpressure monitor on diesel particulate filter that notifies the Permittee when the high backpressure limit of the engine is approached.
   d. The owner or operator of an engine for 2007 or later must comply by assuring that the engine purchased is certified to meet the applicable emissions standards and must install and configure the engine according to the manufacturer's specifications.
   e. The owner/operator must operate and maintain the engine in accordance with the manufacturer's written instructions.
   f. An emergency engine may be operated for maintenance and readiness testing for up to 100 hours per year provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. Operation during an actual emergency is not subject to a limit on hours.
   g. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations.
   h. If the emergency stationary CI ICE of emergency generator is equipped with diesel particulate filter, the Permittee shall keep records of any corrective action taken after the backpressure monitor has notified the Permittee that the high backpressure limit of the engine is approached.

i. No initial notification is required for an emergency use engine. However, the owner or operator must keep records of all the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter, unless the engine is shown to meet the standards applicable to non-emergency use engines.

j. The Permittee shall perform inspections and maintenance on the engine as recommended by the manufacturer per 40 CFR 60.4206 and 40 CFR 60.4211(a). The results of inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request.

k. If the Permittee owns or operates an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purposes specified in Section 2.1 I.2.i.iii(A) of the permit, the Permittee shall submit an annual report according to the requirements at 40 CFR 60.4214(d).

3. <u>15A NCAC 02D .1111 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY</u>
Pursuant to 40 CFR 63.6590(c)(6), this source must meet the requirements of 40 CFR 63 Subpart ZZZZ and Subpart A by meeting the requirements of 40 CFR part 60 subpart IIII. No further requirements apply for this engine under 40 CFR 63 Subpart ZZZZ and Subpart A. If these requirements are not met, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111.

J. One MS4 DSI ACI storage silo (ID No. ES-U4ACISilo) and associated ACI storage silo bin vent filter baghouse (ID No. CD-U4ACISiloBf)

1. <u>15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES</u>

<u>Emission Limit</u>
Emissions of particulate matter from these sources shall not exceed an allowable emission rate as calculated by the following equation:

$E = 4.10 \times P^{0.67}$ (for process rates less than or equal to 30 tons per hour), or
$E = 55.0 \times P^{0.11} - 40$ (for process rates greater than 30 tons per hour)

Where: E = allowable emission rate in pounds per hour
P = process weight in tons per hour

<u>Monitoring/Recordkeeping</u>
Particulate matter emissions from the MS4 DSI ACI storage silo (ID No. ES-U4ACISilo) shall be controlled by the bagfilter (ID No. CD-U4ACISiloBf). To ensure compliance, the Permittee shall perform inspections and maintenance as recommended by the manufacturer. In addition to the manufacturer's inspection and maintenance recommendations, or if there are no manufacturer's inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:

a. A monthly visual inspection of the system ductwork and material collection unit for leaks; and
b. An annual (for each 12-month period following the initial inspection) internal inspection of the bagfilters' structural integrity.

The results of inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

a. The date and time of each recorded action;
b. The results of each inspection;
c. The results of any maintenance performed on the bagfilter; and
d. Any variance from manufacturer's recommendations, if any, and corrections made.

<u>Reporting</u>

The Permittee shall submit the results of any maintenance performed on the bagfilter within 30 days of a written request by the DAQ.

The Permittee shall submit a semi-annual summary report of the monitoring and recordkeeping activities.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Emission Limit
Visible emissions from these sources shall not be more than 20 percent opacity when averaged over a six-minute period.

Monitoring
To ensure compliance, once a month the Permittee shall observe the emissions from the limestone rail unloading station (ID No. ES-6 (RUL)) for any visible emissions above normal. If visible emissions from this source are observed to be above normal, the Permittee shall either: (a) immediately shutdown the source and repair the malfunction, (b) be deemed to be in noncompliance with 15A NCAC 02D .0521 or (c) demonstrate that the percent opacity from the emission points of the emission sources in accordance with 15A NCAC 02D .2610 for 30 minutes is below the limit given above.

Recordkeeping
The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
- i. The date and time of each recorded action;
- ii. The results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
- iii. The results of any corrective actions performed.

Reporting
The Permittee shall submit a semi-annual summary report of the observations.

State-Only Requirement
3. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
See Section V.B.5 above.

K. Wastewater treatment facility lime storage silo (ID No. ES-WWTF Silo) with associated bin vent filter (ID No. CD-WWTF-Silo-BF)

1. 15A NCAC 02D .0510: PARTICULATES FROM SAND, GRAVEL, OR CRUSHED STONE OPERATIONS

The Permittee shall not cause, allow, or permit any material to be produced, handled, transported or stockpiled without taking measures to reduce to a minimum any particulate matter from becoming airborne to prevent exceeding the ambient air quality standards beyond the property line for particulate matter, both PM10 and total suspended particulates.

Fugitive non-process dust emissions shall be controlled by 15A NCAC 02D .0540.

The Permittee shall control emissions from conveyors, screens, and transfer points, such that the applicable opacity standards in Section V.K.2 below are not exceeded.

Monitoring
Particulate matter emissions from this source shall be controlled by the associated bin vent filter. To ensure compliance, the Permittee shall perform inspections and maintenance as recommended by the manufacturer. In addition to the manufacturer's inspection and maintenance recommendations, or if there are no manufacturer's inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:

i. A monthly visual inspection of the system ductwork and material collection unit for leaks; and
ii. An annual (for each 12-month period following the initial inspection) internal inspection of the bin vent filter's structural integrity.

Recordkeeping
The results of the above inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

i. The date and time of each recorded action;
ii. The results of each inspection;
iii. The results of any maintenance performed on the bin vent filter; and
iv. Any variance from manufacturer's recommendations, if any, and corrections made.

Reporting
The Permittee shall submit a semi-annual summary report of the monitoring and recordkeeping activities.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

Emission Limit
Visible emissions from these sources shall not be more than 20 percent opacity when averaged over a six-minute period.

Monitoring
To ensure compliance, once a month the Permittee shall observe the emission points of this source for any visible emissions above normal. The Permittee shall establish "normal" for the source in the first 30 days following start-up of the sources. If visible emissions from this source are observed to be above normal, the Permittee shall either: (a) immediately shutdown the source and repair the malfunction, (b) be deemed to be in noncompliance with 15A NCAC 02D .0521 or (c) demonstrate that the percent opacity from the emission points of the emission sources in accordance with 15A NCAC 02D .2601 for 30 minutes is below the limit given above.

Recordkeeping
The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

i. the date and time of each recorded action;
ii. the results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
iii. the results of any corrective actions performed.

Reporting
The Permittee shall submit a semi-annual summary report of the observations.

3. 15A NCAC 02D .0540: PARTICULATES FROM FUGITIVE NON-PROCESS DUST EMISSION SOURCES
See Section V.B.2 above.

State-Only Requirement
4. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
See Section V.B.5 above

L. Three natural gas-fired, natural gas supply line heaters (ID Nos. ES-HTR1, ES-HTR2 and ES-HTR3)

1. 15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS

   Emission Limit
   Emissions of particulate matter from the combustion of natural gas that are discharged from these sources into the atmosphere shall not exceed 0.081 pounds per million Btu heat input (see Section V.A.15 above).

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for emissions of particulate matter from the firing of natural gas in these sources.

2. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

   Emission Limit
   Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input.

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for sulfur dioxide emissions from the firing of natural gas in these sources.

3. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

   Emission Limit
   Visible emissions from these sources shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period.

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas from these sources.

4. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (40 CFR PART 63, SUBPART DDDDD)
   The facility is major for HAPs and is subject to the MACT Subpart DDDDD for these natural gas-fired heaters.

   These natural gas-fired, natural gas supply line heaters have a heat input of 7 million Btu per hour each and are categorized as having a heat input capacity of less than 10 million Btu per hour.

   These sources burn only natural gas and therefore fall under the "Units Designed to Burn Gas 1 Fuels" subcategory. The following is a summary of the requirements for these sources under MACT Subpart DDDDD.

   - Work practice standards including requirement to conduct a biennial tune-up of these natural gas-fired, natural gas supply line heaters as specified in Table 3 of 40 CFR Part 63 Subpart DDDDD.
   - Work practice standards including inspect the flame pattern, inspect the system controlling the air-to-fuel ratio, optimize total emissions of carbon monoxide, and measure the concentrations in the effluent stream of carbon monoxide in parts per million a requirement to operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.
   - A one-time energy assessment performed by a qualified energy assessor.
   - Maintain records for five years, with at least two years onsite, for each notification and report required to comply with Subpart DDDDD.

- The Permittee shall submit a biennial compliance report.

M. Natural gas supply line pigging operation including fugitive emissions from pig receiver vent (ID No. ES-PIGGING) with associated temporary flare of natural gas from supply line (ID No. CD-PIG FLARE)

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

   Emission Limit
   Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input.

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for sulfur dioxide emissions from the firing of natural gas in this source.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

   Emission Limit
   Visible emissions from these sources shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period.

   Monitoring/Recordkeeping/Reporting
   No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas from this source.

   State-Only Requirement
3. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
   See Section V.B.5 above

N. Coal pile and coal handling (ID No. ES-COALFUG) and Ash landfills and ash handling (ID No. ES-ASHLFFUG)

1. 15A NCAC 02D .0540: PARTICULATES FROM FUGITIVE NON-PROCESS DUST EMISSION SOURCES
   See Section V.B.2 above.

   State-Only Requirement
2. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS
   See Section V.B.5 above

VI. Public Notice

Pursuant to 15A NCAC 02Q .0521, a notice of the draft Title V Operating Permit will be published on the DAQ website to provide for a 30-day comment period with an opportunity for a public hearing. Copies of the draft (proposed) permit, review and public notice will be sent to EPA on for their 45-day review, to persons on the Title V mailing list, to the Mooresville Regional Office, and to the Permittee.

VII. Other Requirements

PE Seal
NA. No controls are being added.

Zoning
There is no expansion of the facility, therefore zoning consistency is not needed.

Fee Classification
The facility fee classification before and after this modification will remain as “Title V”.

VIII. Comments on the Draft Permit

The draft permit and review were sent to Dan Markley at DEC, Melinda Wolanin at the Mooresville Regional Office and Samir Parekh with SSCB on April 27, 2022, for review.

DEC Comments
In an email on May 4, 2022, Scott La Sala responded on behalf of Dan Markley that both their EHS and station personnel have had a chance to review the draft permit. All of the changes noted in the Summary of Changes section have been acknowledged by Duke Energy and there are currently no comments, questions or concerns about the permit.

SSCB Comments
In an email on May 4, 2022, Samir Parekh responded that there were no comments.

Mooresville Regional Comments
No comments were received.

IX. Recommendations

Later after notice.

NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review PART I

Issue Date: 05/03/2019

Region: Mooresville Regional Office
County: Catawba
NC Facility ID: 1800073
Inspector's Name: Melinda Wolanin
Date of Last Inspection: 01/23/2019
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Marshall Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Marshall Steam Station
8320 East NC Hwy 150
Terrell, NC 28682

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 02D. 0503, 02D .0516, 02D .0521, 02Q .0504, 02D .0530(u), 02D .1111
NSPS: NA
NESHAP: 40 CFR Part 63, Subpart DDDDD
PSD: NA
PSD Avoidance: NA
NC Toxics: 02D .1100, 02Q .0711
112(r): NA
Other: NA

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Joseph (Scott) La Sala Lead EHS Professional (828) 478-7820 8320 East NC Hwy 150 Terrell, NC 28682	Rick Roper General Manager (828) 478-7600 8320 East NC Hwy 150 Terrell, NC 28682	Ann Quillian Lead Environmental Specialist (919) 546-6610 410 South Wilmington Street Raleigh, NC 27601

Application Data

Application Number: 1800073.18B
Date Received: 10/03/2018
Application Type: Modification
Application Schedule: TV-Sign-501(b)(2) Part I

Existing Permit Data

Existing Permit Number: 03676/T56
Existing Permit Issue Date: 12/20/2018
Existing Permit Expiration Date: 07/31/2022

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2017	4362.01	9545.81	111.17	2446.55	346.03	29.70	13.69 [Hydrogen chloride (hydrochlori]
2016	4919.01	9389.15	117.18	2917.11	375.48	31.35	14.58 [Hydrogen chloride (hydrochlori]
2015	4623.95	8824.34	92.81	1552.52	954.11	97.06	79.08 [Hydrogen chloride (hydrochlori]
2014	5917.45	9917.04	100.94	2180.70	1004.30	99.98	84.76 [Hydrogen chloride (hydrochlori]
2013	4703.86	11854.28	89.99	1952.62	1201.47	105.27	86.10 [Hydrogen chloride (hydrochlori]

Review Engineer: Ed Martin

Review Engineer's Signature: **Date:** 05/03/2019

Comments / Recommendations:
Issue 03676/T57
Permit Issue Date: 05/03/2019
Permit Expiration Date: 07/31/2022

Chronology

October 3, 2018	Application received.
October 25, 2018	Email to Ann Quillian at Duke requesting information on the toxics analysis.
October 26, 2018	A Zoning Consistency Determination form signed by Catawba County Planning and Parks was received.
November 5, 2018	Email received from Matthew Porter, Air Quality Analysis Branch (AQAB), who was reviewing the toxics modeling submitted with the application, concerning several modeling issues. At the same time, the AQAB was also reviewing the toxics modeling submitted with application 1800073.18A for the Marshall wastewater treatment facility modification. Modeling for that project and this project is very similar. Matthew had some questions on this (natural gas co-firing) project and there were also questions regarding which sources were to be included in the modeling.
November 7, 2018	Email from Matthew Porter to Philip Crawford, Ann Quillian, Tom Anderson, Mark Yoder and Ed Martin with Division of Air Quality's (DAQ's) comments on the modeling.
November 8, 2018	Email from Ann Quillian responding to DAQ's October 25, 2018 modeling questions. Also, DEC asked, that if a revised TAPs dispersion modeling run is required with the changes being discussed, whether they could be addressed either in the Part II application submittal for this wastewater project, or within 90 days of the Part I issuance, or as part of the Marshall natural gas co-firing project.
November 21, 2018	Email to Ann Quillian to notify Duke that DAQ would allow the necessary revised toxics modeling to be submitted within 90 days of issuance (on December 20, 2018) of the Part I permit for the wastewater treatment modification (as stated in that permit) since the modeling review for that project could not be completed and approved at the time of permit issuance, in order to meet the equipment startup schedule.
November 26, 2018	Conference call among Ann Quillian, Cyndi Winston, Mark Yoder, Philip Crawford, Matthew Porter and Ed Martin to discuss toxics modeling issues related to the wastewater treatment and natural gas co-firing project applications.
November 29, 2018	Email to Ann Quillian to summarize the changes DAQ felt were necessary for the revised toxics modeling.
March 18, 2019	The revised toxics analysis and application addendum was received from DEC (see page 16).
April 18, 2019	DEC's toxics dispersion modeling analysis was approved by Matthew Porter, AQAB.
April 22, 2019	Sent draft permit and review to Ann Quillian at DEC, Melinda Wolanin (Mooresville Regional Office) and Samir Parekh (Stationary Source Compliance Branch) for review.
April 29, 2019	Comments on draft permit received from DEC (see Section VII). No other comments received.
May 3, 2019	The permit was issued.

I. Purpose of Application

Duke Energy Carolinas, LLC (DEC) is proposing to add natural gas co-firing capability to Units 1 through 4. As part of the project, Piedmont Natural Gas (PNG) will also install three 7 million British thermal units per hour (mmBtu/hr) natural gas heaters on the new natural gas supply line. PNG also plans to conduct "pigging" of the new natural gas line once every 5 to 7 years for routine inspections. The actual fuel mix fired in Units 1 through 4 will be based on cost, availability, and demand. The projected actual emissions are based on a 12-month fuel heat input use of 92.5% for burning coal, 7.1% for burning natural gas, and 0.44% for burning oil for Units 1 and 2 (each unit); 50% for burning coal, 50% for burning natural gas, and 0.26% for burning oil for Unit 3; and 51% for burning coal, 48% for burning natural gas, and 0.25% for burning oil for Unit 4. The project does not affect the originally permitted heat input of the boilers.

DEC requested that the application be processed using the two-step Title V process pursuant to rules 15A NCAC 02Q .0501(b)(2) and .0504. DEC will be required to submit an application for a Title V operating permit pursuant to 15A NCAC 02Q .0500 within 12 months of commencement of operation for these changes.

II. Permit Changes

The following changes were made to the DEC - Marshall Steam Station Air Permit No. 03676T56:

Old Page	Old Section	New Page	New Section	Description of Change(s)
Cover	--	Cover	--	Amended permit numbers and dates.
			Insignificant Activities List	Removed: I-1, I-2, I-4 through I-6, I-22, I-23, I-31, I-34, I-40, I-41 through I-45, I- 47 through I-53, I-58, I-61 through I-63, I-65 through I-70, I-74, I-88, I-91, I-95, I-97 through I-99. Revised: I-12, I-13, I-24, I-26, I-75 and I-136. Added: I-147.
various	regulation tables	various	regulation tables	Added 15A NCAC 02D .1100 as an applicable regulation for equipment in Sections 2.1.B, D, E, F, H, J and K.
3-6	1, table of permitted emission sources	3-6	1, table of permitted emission sources	Revised emission source description for ES-1 through ES-4 from “One No. 2 fuel oil/coal-fired electric utility boiler” to “One No. 2 fuel oil/natural gas/coal-fired electric utility boiler.” Added sources: ES-HTR1, ES-HTR2, ES-HTR3, ES-PIGGING, ES-COALFUG and ES-ASHLFFUG. Added footnote *** for the Units 1-4 electrostatic precipitators and FGD systems. Added footnote + for the new emission sources (ID Nos. ES-HTR1, ES-HTR2, ES-HTR3, ES-PIGGING, ES-COALFUG and ES-ASHLFFUG) and control device (ID No. CD-PIG FLARE).
7	2.1.A, equipment description	7	2.1.A, equipment description	Revised emission source description for ES-1 through ES-4 from “One coal/No. 2 fuel oil-fired electric utility boiler …” to “One No. 2 fuel oil/natural gas/coal-fired electric utility boiler …”
8-9	2.1.A, regulation table	8-9	2.1.A, regulation table	Added gas for 15A NCAC 02D .0519 limits. Added 15A NCAC 02D .0530(u) and 15A NCAC 02Q .0504.
10	2.1.A.2	10	2.1.A.2	Added gas.
17	2.1.A.8	17	2.1.A.8	Removed Subpart BBBBB "CSAPR NOx Ozone Season Trading Program".
18	2.1.A.12.a	18	2.1.A.12.a	Added natural gas.

--	--	26	2.1.A.17	Added 15A NCAC 02D .0530(u) condition.
--	--	47-49	2.1.L	Added for the new natural gas-fired natural gas supply line heaters ES-HTR1, ES-HTR2 and ES-HTR3.
--	--	50	2.1.M	Added for the natural gas supply line pigging operation ES-PIGGING.
--	--	51	2.1.N	Added for coal pile and coal handling (ID No. ES-COALFUG) and ash landfills and ash handling (ID No. ES-ASHLFFUG).
48	2.2.A	52	2.2.A	Added coal pile and coal handling (ID No. ES-COALFUG) and ash landfills and ash handling (ID No. ES-ASHLFFUG).
49	2.2.B.1	53-57	2.2.B.1	Added facility-wide toxic emission limits.
--	--	58	2.2.B.2	Added TPER limit condition.
--	--	59	2.2.C	Added requirement to file an amended application for completion of the two-step significant modification process within one year from the date the first of sources ES-1 through ES-4, ES-HTR1, ES-HTR2, ES-HTR3 or ES-PIGGING begins to burn natural gas.
50-51	2.3.B	60-61	2.3.B	Revised I-12 and I-13 descriptions and added I-138 and I-147 to match insignificant activities list.

III. Facility Description

DEC Marshall Steam Station is an electric utility that generates electrical power. The Marshall Steam Station is permitted for four No. 2 fuel oil/natural gas/coal-fired electric utility boilers (ID Nos. ES-1, ES-2, ES-3, ES-4) and various supporting equipment.

IV. Project Emissions

A. Emission Factors

To calculate emissions from the project, DEC used appropriate emission factors and throughputs. The emission factor sources include:

U.S. EPA AP-42 Emission Factors
Emission factors from U.S. EPA's AP-42 document (5th edition unless otherwise noted) were relied upon to calculate emissions from the project where test data, manufacturer guarantees, and EPRI factors were not available or representative. The following AP-42 sections were utilized to obtain emission factor data:

- Section 1.1, Bituminous and Subbituminous Coal Combustion;
- Section 1.3, Fuel Oil Combustion;
- Section 1.4, Natural Gas Combustion; and
- Section 13.5, Industrial Flares.

PM10 and PM2.5 Emission Factors for Natural Gas Combustion
The EPA's spreadsheet, *Emissions Factors for Particulate Matter from Natural Gas Combustion (xls)* found on their 2014 NEI documentation page (https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-documentation). The reference section states that the "EPA believes that the current AP-42 factors for condensable emissions are too high based on some limited data from a pilot-scale dilution sampling method that is similar to EPA's CTM 39." EPA's Roy Huntley developed corrected emission factors from preliminary test data gathered by Ron Myers (EPA) who was the lead on the development of a condensable PM test method at the time. The spreadsheet was last updated in 2012 and provides adjusted particulate matter emission factors for natural gas, process gas, and LPG combustion in boilers, engines, and heaters as listed. Rich Mason of the EPA confirmed

with EPA emission factor experts that natural gas emission factors posted to the NEI/WebFIRE pages are valid replacements to the old AP-42 (and WebFIRE) emission factors.

The emissions calculations in the application utilize the condensable PM, PM10 filterable, and PM2.5 filterable emission factors for natural gas fired boilers that are referenced from the “Final table with Natural Gas Adjustment factors Nov 21 2006.xls.” PM filterable is not addressed in this spreadsheet therefore the AP-42 Section 1.4 factor was retained. The ammonia emission factor was also utilized from this reference.

Electric Power Research Institute (EPRI) Data
EPRI is a nonprofit organization that conducts research on the power industry. EPRI’s research is supported by electric utilities, government agencies, and corporations. DEC used emission factors from EPRI Report, *Guidelines for Estimating Trace Substance Emissions from Fossil-Fuel-Fired Steam Electric Power Plants, 2014 Technical Report* for certain specified sources.

Site Specific Data and Vendor Guarantees
Historical stack test and CEMS data were used to estimate emissions from existing sources where data was available and is preferred over published emission factors by EPRI or the EPA. In addition, the gas burner vendor provided emission guarantees for NOx, CO, and VOC as either a specific emission factor, or the pre-outage baseline, whichever is greater. VOC emissions were estimated using the maximum vendor emission guarantee for Units 1 through 4.

CO emissions were estimated using the results of boiler testing conducted in April 2018 because the results were greater than the vendor-provided emission factor. As presented in the boiler test report, which is included in Appendix F of this application, multiple boiler operating scenarios were evaluated. CO emission rates from the scenarios most representative of normal full load operation were selected to estimate emissions. The selected scenarios are identified in Table B-17 of Appendix B of the application.

NOx emissions were estimated using the average of 2017 CEMS data for Units 1, 2, and 4 and the maximum vendor guarantee for Unit 3. Vendor emission guarantees were also used to estimate emissions of NOx, VOC, and CO from natural gas combustion in the heaters.

Regulatory and Permit Limits
Potential emissions are estimated using permit limits, as applicable.

Greenhouse Gas Emission Factors
The U.S. EPA Mandatory Greenhouse Gas (GHG) reporting rule emission factors and global warming potentials from Subparts A and C were used to calculate emissions from carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) from combustion. Tables C-1 and C-2 to Subpart C of Part 98 list default CO_2, CH_4, and N_2O emission factors and high heat values for various fuel types. N_2O emissions from flaring natural gas during the pigging operation were calculated using 40 CFR Part 98, Subpart W, equation W-40.

B. Project Emissions

A. PSD Applicability
The Marshall Steam Station is an existing Prevention of Significant Deterioration (PSD) “major stationary source” of criteria air pollutants as defined under PSD, per 40 CFR 51.166(b)(1)(i)(a), and is classified as one of the 28 named source categories under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input," which emits or has a potential to emit (PTE) 100 tons per year of any regulated pollutant.

Because the existing facility is considered a major stationary source, any physical change or a change in the method of operation as calculated pursuant to 40 CFR 51.166(a)(7)(iv) which results in a *net emissions increase* for regulated pollutants in the amounts equal or greater than the significance levels, is subject to PSD review and must meet certain review requirements. Thus, the net emission increase as a result of this modification must be compared to the "significance levels" as listed in 40 CFR 51.166(b)(23)(i) to determine which pollutants must undergo PSD review.

The Permittee has performed a PSD applicability analysis for the project to determine whether the project resulted in an emission increase of any regulated NSR pollutant above the applicable significance thresholds. The PSD applicability analysis evaluated all applicable PSD-regulated air pollutants to be emitted, including NOx, PM (filterable), PM_{10}, $PM_{2.5}$, SO_2, VOCs, CO, HF, Pb, sulfuric acid (H_2SO_4), TRS, and carbon dioxide as CO_2e. The following describes the methodology used to determine the increases for the existing and new units:

<u>PSD Applicability Test for Existing Units</u>
For the existing units (Units 1 through 4), the *actual-to-projected actual test* was used in accordance with 40 CFR 51.166(a)(7)(iv)(c) to compare the difference between the *projected actual emissions* and the *baseline actual emissions* for each existing emissions unit as follows:

<u>Projected Actual Emissions for Existing Units</u>
In accordance with 40 CFR 40 51.166(b)(40)(i), *projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source.

To determine the maximum annual rate, a source must consider all relevant information, including historical operational data, the company's expected business activity, and the company’s highest projections of business activity for the five-year period after implementation of the project.

This project does not involve increasing the permitted heat input (design capacity) or the potential to emit of the existing sources (Units 1 through 4).

Projected actual (Post-project) emissions for the addition of natural gas firing capability for the existing Units 1 through 4 are based on the 5-year fuel use projection of combined coal, gas, and oil firing for each unit and the maximum projected 12-month heat input during that period, assuming natural gas is available year-round. Projected actual consumption of No. 2 fuel oil is based on the maximum 24-month average from 2013 through 2017 for each unit.

The projected 12-month fuel heat input use for Units 1 and 2 (each unit) during this 5-year period is 16,908,220 mmBtu (92.5%) for burning coal, 1,293,000 mmBtu (7.1%) for burning natural gas, and 80,776 mmBtu (0.44%) for burning oil.

The projected 12-month fuel heat input use for Unit 3 during this 5-year period is 14,321,700 mmBtu (50%) for burning coal, 14,449,820 mmBtu (50%) for burning natural gas, and 75,757 mmBtu (0.26%) for burning oil.

The projected 12-month fuel heat input use for Unit 4 during this 5-year period is 14,847,880 mmBtu (51%) for burning coal, 13,962,110 mmBtu (48%) for burning natural gas, and 73,463 mmBtu (0.25%) for burning oil.

The projected actual emissions for the existing sources are shown in Table 1.

Table 1 – Projected Actual Emissions for Existing Sources

Regulated NSR Pollutant	Projected Actual Emissions, tpy*									
	Unit 1 and Unit 2 (total)			Unit 3			Unit 4			Total
	coal	gas	oil	coal	gas	oil	coal	gas	oil	
NOx (as NO_2)	2,298	175.7	10.98	1,352	1,364	4.07	1,863	1,752	9.2	8,828.9
PM (filterable)	44.7	1.20	6.00E-01	26.2	13.5	5.62E-01	45.6	13.0	5.45E-01	145.91
PM_{10}	64.7	3.30-01	8.07E-01	66.1	3.68	7.56E-01	77.3	3.56	7.34E-01	217.967
$PM_{2.5}$	50.8	2.73E-01	6.93E-01	57.9	3.05	6.49E-01	63.1	2.94	6.30E-01	180.035
SO_2	1,026	3.80E-01	4.90	1,677	4.25	5.17	1,579	4.11	4.56	4,305.37
VOC	21.1	3.56	5.87E-02	17.9	39.7	5.50E-02	18.6	38.4	5.34E-02	139.42
CO	779	59.6	1.47	622	627	1.37	1,504	1,415	1.33	5,010.77
HF	1.52	--	4.48E-03	1.22	--	4.20E-03	1.26	--	4.08E-03	4.013
Lead	1.11E-02	3.17E-04	2.02E-04	4.78E-03	3.54E-03	1.89E-04	8.71E-03	3.42E-03	1.84E-04	3.24E-02
Sulfuric Acid Mist	45.4	--	3.44E-04	49.2	--	3.22E-04	31.5	--	3.13E-04	126.10
GHG as CO_{2e}	1,748,764	75,545	6,594	1,481,226	844,249	6,184	1,535,672	815,754	5,997	6,519,985

* From application Tables B-6, 7 and 8

Baseline Actual Emissions for Existing Units

In accordance with 15A NCAC 2D .0530(b)(1)(A), *baseline actual emissions* for an existing emissions unit are calculated as 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 five-year period immediately preceding the date that a complete permit application is received. However, the Director shall allow a different time period, not to exceed 10 years immediately preceding the date on which a complete permit application is received by the Division, if the owner or operator demonstrates that it is more representative of normal source operation. In accordance with 15A NCAC 2D .0530(b)(1)(a)(v), for a regulated NSR pollutant, if a project involves multiple emissions units, only one consecutive 24-month period shall be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period for each regulated NSR pollutant may be used for each regulated NSR pollutant.

For this project, varying baseline periods were selected between 2013 and 2017 for the various pollutants (see Appendix B of the application). *Baseline actual emissions* represent the highest historical 24-month average annual emissions in tons per year for each pollutant.

The baseline emissions for the existing sources are shown in Table 2.

Table 2 - Baseline Actual Emissions for Existing Sources

Regulated NSR Pollutant	24 Month Baseline Period	Baseline Actual Emissions, tpy (average for 24 months)*			
		Unit 1 and 2 (total)	Unit 3	Unit 4	Total
NOx (as NO_2)	Oct 2013 – Sep 2015	4,051	2,575.65	3,801.5	10,428.15
PM (filterable)	Oct 2013 – Sep 2015	77.79	62.47	86.755	227.02
PM_{10}	Oct 2013 – Sep 2015	114.63	158.8	133.0	406.43
$PM_{2.5}$	Oct 2013 – Sep 2015	90.58	139.5	106.15	336.23
SO_2	Oct 2013 – Sep 2015	1862.3	2363.25	1,404.2	5,629.75
VOC	Jan 2016 – Dec 2017	27.77	41.37	44.455	113.60
CO	Jan 2016 – Dec 2017	1,023.25	1,436.15	3,600.9	6,060.3
HF	Jan 2016 – Dec 2017	2.045	2.905	3.12	8.07
Lead	Jan 2016 – Dec 2017	1.505E-02	1.155E-02	2.165E-02	4.825E-02
Sulfuric Acid Mist	Jan 2016 – Dec 2017	60.25	117.02	77.885	255.155
GHG as CO_{2e}	Jan 2016 – Dec 2017	2,352,539	3,537,683.5	3,798,286.5	9,688,509

* From application Tables B-2 through B-4.

Total Increase for Existing Units

The total increase for the existing units is the difference between the *projected actual emissions* from Table 1 and the *baseline actual emissions* from Table 2 as shown in Table 3.

Table 3 – Total Emissions Increase for Existing Sources

Regulated NSR Pollutant	Projected Actual Emissions Minus Baseline Emissions, tpy		
	Projected Actual Emissions*	Baseline Actual Emissions**	Total Net Increase
NOx (as NO_2)	8,828.9	10,428.15	-1,599.25
PM (filterable)	145.91	227.02	-81.11
PM_{10}	217.967	406.43	-188.463
$PM_{2.5}$	180.035	336.23	-156.195
SO_2	4,305.37	5,629.75	-1,324.38
VOC	139.42	113.60	25.82
CO	5,010.77	6,060.3	-1,049.53
HF	4.013	8.07	-4.057
Lead	3.24E-02	4.825E-02	-1.585E-02
Sulfuric Acid Mist	126.10	255.155	-129.055
GHG as CO_{2e}	6,519,985	9,688,509	-3,168,524

* From Table 1
** From Table 2

PSD Applicability Test for New Units

For the new units (natural gas heaters ES-HTR1, ES-HTR2, ES-HTR3 and natural gas line pigging operations ES-PIGGING), the *actual-to-potential test* was used in accordance with 40 CFR 51.166(a)(7)(iv)(d) to compare the difference between the *potential to emit* from each new emissions unit following completion of the project and the *baseline actual emissions* as follows:

Potential to Emit for New Units

In accordance with 15A NCAC 2D .0530(b)(4), *potential to emit* means the maximum capacity of a stationary 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 restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

Emissions were also calculated for the pigging of the natural gas line that is expected to occur once every 7 years. Emissions from pigging operations were based on engineering calculations using site-specific data and natural gas composition information. Pig receiver venting emissions were estimated assuming the entire internal volume of the receiver is vented to atmosphere each time a pig is received. NOx and CO emissions from flaring the natural gas supply during pigging operations were calculated using emission factors from AP-42, Table 13.5-1 and 13.5-2.

N_2O emissions from flaring were calculated using 40 CFR Part 98, Subpart W, equation W-40. VOC, methane, and organic HAP emissions were estimated using the supplier natural gas composition information and an assumed 98 percent destruction efficiency. SO_2 and CO_2 emissions from flaring were calculated using mass balance.

The potential emissions for the new sources are shown in Table 3.

Table 4 – Potential Emissions for New Sources

Regulated NSR Pollutant	Potential Emissions, tpy*			
	Natural Gas Heaters	Pigging Fugitive	Flare	Total
	gas fired	gas released	gas burned	
NOx (as NO_2)	14.3	ND	4.53E-01	14.753
PM (filterable)	1.71E-01	ND	ND	1.71E-01
PM_{10}	4.69E-02	ND	ND	4.69E-02
$PM_{2.5}$	3.88E-02	ND	ND	3.88E-02
SO_2	5.41E-02	ND	7.44E-02	1.285E-01
VOC	2.02	1.71E-02	9.74E-01	3.01
CO	9.20	ND	2.07	11.27
HF	ND	ND	ND	ND
Lead	4.51E-05	ND	ND	4.51E-05
Sulfuric Acid Mist	ND	ND	ND	ND
GHG as CO_{2e}	10,748	2.2	958	11,708.2
TRS		2.59E-05	1.47E-03	1.47E-03

* From application Tables B-9 through B11

Baseline Actual Emissions for New Units

In accordance with 15A NCAC 2D .0530(b)(1)(B), for a new emissions unit the *baseline actual emissions* shall equal zero and thereafter, for all other purposes, shall equal the unit's potential to emit.

Total Increase for New Units

The total increase for the new units is the difference between the *potential to emit* from Table 4 and the *baseline actual emissions* of zero or simply the potential emissions.

Total Increase for Existing and New Sources

The total net increase in emissions for the project is the increase for the existing sources from Table 3 plus the increase in potential emissions for the new sources from Table 4 as shown in Table 5. The total project emissions increases demonstrate that all pollutants are below the PSD significant emission rates and New Source Review is not required. (Appendix B of the application contains the project emissions calculations).

Table 5 – Emissions Increases for Proposed Project, tpy

Regulated NSR Pollutant	Increases for Existing Sources*	Increases for New Sources**	Net Emissions Increase/Decrease	Significant Emission Rate	Major Modification Review Required?
NOx (as NO_2)	-1,599.25	14.753	-1,584.5	40	No
PM (filterable)	-81.11	1.71E-01	-80.9	25	No
PM_{10}	-188.463	4.69E-02	-188.4	15	No
$PM_{2.5}$	-156.195	3.88E-02	-156.2	10	No
SO_2	-1,324.38	1.285E-01	-1,324.3	40	No
VOC	25.82	3.01	28.8	40	No
CO	-1,049.53	11.27	-1,038.3	100	No
HF	-4.057	ND	-4.057	3	No
Lead	-1.585E-02	4.51E-05	-1.58E-02	0.6	No
Sulfuric Acid Mist	-129.055	ND	-129.1	7	No
GHG as CO_{2e}	-3,168,524	11,708.2	-3,156,816	75,000	No
TRS		1.47E-03	1.47E-03	10	No

* From Table 3
** From Table 4

Table 6 – Projected Actual Emissions for the 02D .0530(u) Condition, tpy

Regulated NSR Pollutant	Projected Actual Emissions		
	Unit 1 and Unit 2	Unit 3	Unit 4
NOx (as NO_2)	2,484.7	2,720.1	3,624.2
PM (filterable)	46.5	40.3	59.1
PM_{10}	65.8	70.5	81.6
$PM_{2.5}$	51.8	61.6	66.7
SO_2	1,031.3	1,686.4	1,587.7
VOC	24.7	57.7	57.1
CO	840.1	1,250.4	2,920.3
HF	1.52	1.22	1.26
Lead	1.16E-02	8.51E-03	1.23E-02
Sulfuric Acid Mist	45.4	49.2	31.5
GHG as CO_{2e}	1,830,903	2,331,659	2,357,423

V. Source-by-Source Regulatory Evaluation

A. Existing sources

The following existing sources and regulations are affected by this modification:

1. **One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-1) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-1c (U1SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-2), electrostatic precipitator (ID No. CD-3), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U1/2FGD)**

   One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-2) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-4c (U2SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-5), electrostatic precipitator (ID No. CD-6), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U1/2FGD)

   One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-3) and associated selective catalytic reduction system (SCR) NOx reduction system (ID No. CD-7c (SCR)), electrostatic precipitator (ID No. CD-9 (ESPnew)), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U3FGD)

   One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-4) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-11c (U4SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-12), powdered activated carbon system (ID No. CD-U4ActC), electrostatic precipitator (ID No. CD-13 (ESPnew)), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U4FGD)

   <u>15A NCAC 02D .0519: CONTROL OF NITROGEN OXIDES EMISSIONS</u>
   Emissions of nitrogen oxides from these sources when burning coal and/or oil shall be calculated by the following equation:

   $$E = [(Ec)(Qc) + (Eo)(Qo)]/Qt$$

   Where: E = emission limit for combined burning of coal and gas in pounds per million Btu heat input
   Ec = 1.8 pounds per million Btu heat input for coal only
   Eo = 0.8 pounds per million Btu heat input for oil or gas
   Qc = coal heat input in Btu per hour
   Qo = gas heat input in Btu per hour
   Qt = Qc + Qo

   The only change to this regulation is to add gas to the condition; however, no change is required for co-firing natural gas with coal since the emission limit for gas, Eo, of 0.8 pounds per million Btu heat input is the same as for oil.

   <u>15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (40 CFR PART 63, SUBPART UUUUU)</u>
   Subpart UUUUU MACT, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units" (MATS rule) applies to any coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart as specified in §63.9981.

No change to this regulation is required for co-firing natural gas with coal and oil. However, if these sources burn natural gas to the extent that coal and oil is not burned for more than 10.0 percent of the average annual heat input during the 3 previous calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, they would not meet the definition of a *Coal-fired electric utility steam generating unit* and would therefore no longer be subject to Subpart UUUUU.

b. New applicable regulations
The following new regulations apply:

15A NCAC 2D .0530(u): USE OF PROJECTED ACTUAL EMISSIONS TO AVOID APPLICABILITY OF PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS
Under 15A NCAC 2D .0530(u), for projects at existing emissions units at a major stationary source, the owner or operator may elect to use *projected actual emissions* to avoid applicability of prevention of significant deterioration requirements. DEC has provided *projected actual emissions* for all applicable PSD-regulated air pollutants to be emitted, including NOx, PM (filterable), PM_{10}, $PM_{2.5}$, SO_2, VOCs, CO, HF, Pb, sulfuric acid (H_2SO_4), TRS, and carbon dioxide as CO_2e, as shown in Table 1 for the existing sources (ES-1 through ES-4). All those pollutants have been demonstrated to not exceed the PSD significance level as shown in Table 5. Therefore, the owner or operator shall maintain records of annual emissions in tons per year, on a calendar year basis related to the modification, for these pollutants for 10 years following resumption of regular operations after the change if the project involves increasing the emissions unit's design capacity or its potential to emit the regulated NSR pollutant; otherwise, these records shall be maintained for five years following resumption of regular operations after the change. The owner or operator shall submit a report to the Director within 60 days after the end of each year during which these records must be generated. This project does not involve increasing the emissions unit's design capacity or its potential to emit; therefore, records of annual emissions shall be maintained for five years. DECs post-project emissions for the addition of natural gas co-firing capability to Units 1 through 4 are based on the 5-year fuel use projection and the maximum projected 12-month heat input during that period, assuming natural gas is available year-round. Projected actual emissions are based on a combination of coal, gas and oil firing as shown in Section IV.B above. The *projected actual emissions* shown in Table 6 are placed in the 02D .0530(u) permit condition.

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
See Section V.C.2 below.

B. New Sources

The following new sources are being added:

1. Three natural gas-fired, natural gas supply line heater (ID Nos. ES-HTR1, ES-HTR2 and ES-HTR3)

The following regulations apply to these sources:

15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
Emissions of particulate matter from the combustion of natural gas that are discharged from these sources into the atmosphere shall not exceed 0.081 pounds per million Btu heat input as calculated below.

This rule applies to installations burning fuel, including natural gas and fuel oils, for the purpose of producing heat or power by indirect heat transfer. For the purpose of this rule, the maximum heat input shall be the total heat content of all fuels which are burned in a fuel burning indirect heat exchanger, of which the combustion products are emitted through a stack or stacks. The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger. Fuel burning indirect heat exchangers constructed or permitted after February 1, 1983, shall not change the allowable emission limit of any fuel burning indirect heat exchanger whose allowable emission limit has previously been set. The removal of a fuel burning indirect heat exchanger shall not change the allowable emission limit of any fuel burning indirect heat exchanger whose allowable emission limit has previously been established. However, for any fuel burning indirect heat exchanger constructed after, or in conjunction with, the removal of another fuel burning indirect heat exchanger at the plant site, the maximum heat input of the removed fuel burning indirect heat exchanger shall no longer be considered in the determination of the allowable emission limit of any fuel burning indirect heat exchanger constructed after or in conjunction with the removal. The emission rate for these sources is determined below.

The facility-wide heat inputs will be as follows:

Source	Heat Input (mmBtu/hr)
Boiler ES-1 (existing)	4,230
Boiler ES-2 (existing)	4,230
Boiler ES-3 (existing)	7,110
Boiler ES-4 (existing)	7,110
ES-HTR1 natural gas supply line heater (new)	7
ES-HTR2 natural gas supply line heater (new)	7
ES-HTR3 natural gas supply line heater (new)	7
Total	22,701

Allowable emissions of particulate matter from fuel combustion shall be calculated as follows:

$$E = 1.090\ Q^{-0.2594}$$

where: E = allowable particulate emission rate, pounds per million Btu
Q = maximum heat input rate (total at plant site), million Btu per hour

Therefore, emissions of particulate matter from the combustion turbines shall not exceed the following:

$$E = 1.090\ Q^{-0.2594}$$
$$= 1.090\ (22{,}701)^{-.2594}$$
$$= \mathbf{0.081\ lb/mmBtu}$$

Compliance
Since these heaters will only fire natural gas, emissions of particulate matter will be much less than the above limit and therefore no monitoring/recordkeeping/reporting is required for emissions of particulate matter from this source to assure compliance with this regulation.

Compliance
No monitoring, recordkeeping, or reporting is required for emissions of particulate matter from the firing of natural gas in these sources.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Compliance
No monitoring, recordkeeping, or reporting is required for sulfur dioxide emissions from the firing of natural gas in these sources.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
Visible emissions from these sources shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period. However, six-minute

averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Compliance
No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas in these sources.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR PART 63, SUBPART DDDDD)
As specified in Subpart DDDDD §63.7485, this subpart applies to owners or operators of industrial, commercial, or institutional boilers or process heaters as defined in §63.7575 that is located at, or is part of, a major source of HAP (as defined in §63.2), except as specified in §63.7491. This subpart applies to new, reconstructed, and existing affected sources as follows:

> The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.
>
> The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

A boiler or process heater is new if construction is commenced after June 4, 2010. A boiler or process heater is existing if it is not new or reconstructed. These heaters are new sources under Subpart DDDDD.

These heaters will burn natural gas and therefore are classified as *Unit designed to burn gas 1 subcategory* as listed in §63.7499(l).

The following Subpart DDDDD sections apply:

Permit Section	Subpart DDDDD Section	Subpart DDDDD Requirement
2.1.K.4.a.i	§63.7495(a)	If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.
2.1.K.4.h 2.1.K.4.k 2.1.K.4.l	§63.7540(a)	You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.
2.1.K.4.h	§63.7540(a)(11)	If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.
2.1.K.4.h	§63.7500(e)	Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.
2.1.K.4.i	§63.7510(g)	For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable biennial schedule as specified in §63.7515(d) following the initial compliance date.

		Thereafter, you are required to complete the applicable biennial tune-up as specified in §63.7515(d).
2.1.K.4.j	§63.7515(d)	If you are required to meet an applicable tune-up work practice standard, you must conduct a biennial tune-up according to §63.7540(a)(11). Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed affected source, the first biennial tune-up must be no later than 25 months after the initial startup of the new affected source.
2.1.K.4.n	§63.7550(b)	For units that are subject only to a requirement to conduct subsequent biennial tune-up according to §63.7540(a)(11), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only a biennial compliance report as specified in paragraphs (b)(1) through (4) of this section according to the dates the permitting authority has established instead of a semi-annual compliance report.

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
See Section V.C.2 below.

2. Natural gas supply line pigging operation including fugitive emissions from pig receiver vent (ID No. ES-PIGGING) with associated temporary flare of natural gas from supply line (ID No. CD-PIG FLARE)

The following regulations apply to this source:

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Compliance
No monitoring/recordkeeping/reporting is required for sulfur dioxide emissions from the firing of natural gas in this source

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
Visible emissions from these sources shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Compliance
No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas from this source.

State-Only Requirement
15A NCAC 02D .1100 CONTROL OF TOXIC AIR POLLUTANTS
See Section V.C.1 below.

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
See Section V.C.2 below.

C. Multiple Emission Sources

The following regulations apply to multiple emission sources:

1. Facility-wide Toxics Demonstration

State-Only Requirement
15A NCAC 02D .1100 CONTROL OF TOXIC AIR POLLUTANTS
As a result of this modification to add natural gas co-firing, a facility-wide toxics modeling analysis is triggered for the toxic pollutants emitted by these sources.

In accordance with 15A NCAC 02Q .0709(a), the owner or operator of a source who is applying for a permit or permit modification to emit toxic air pollutants shall:

i. demonstrate to the satisfaction of the Director through dispersion modeling that the emissions of toxic air pollutants from the facility will not cause any acceptable ambient level listed in 15A NCAC 02D .1104 to be exceeded beyond the premises (adjacent property boundary); or
ii. demonstrate to the satisfaction of the Commission or its delegate that the ambient concentration beyond the premises (adjacent property boundary) for the subject toxic air pollutant shall not adversely affect human health (e.g., a risk assessment specific to the facility) though the concentration is higher than the acceptable ambient level in 15A NCAC 02D .1104.

As required by NCAC 02Q .0706(b), the owner or operator of the facility shall submit a permit application to comply with 15A NCAC 02D .1100 if the modification results in:

i. a net increase in emissions or ambient concentration of any toxic air pollutant that the facility was emitting before the modification; or
ii. emissions of any toxic air pollutant that the facility was not emitting before the modification if such emissions exceed the levels contained in 15A NCAC 02Q .0711.

As required by NCAC 02Q .0706(c), the permit application shall include an evaluation for all toxic air pollutants covered under 15A NCAC 02D .1104 for which there is:

i. a net increase in emissions of any toxic air pollutant that the facility was emitting before the modification; and
ii. emission of any toxic air pollutant that the facility was not emitting before the modification if such emissions exceed the levels contained in 15A NCAC 02Q .0711.

All sources at the facility, excluding sources exempt from evaluation in 15A NCAC 02Q .0702, emitting these toxic air pollutants shall be included in the evaluation.

When the AQAB began review of the toxics modeling submitted with this application, the modeling for application 1800073.18A for the Marshall wastewater treatment facility modification was also under review. Because of questions and concerns raised by DAQ on the wastewater treatment application modeling, mainly concerning the basis of wind erosion emissions modeled from on-site storage piles, and other issues discussed below, and in order to meet DEC's schedule for startup of that equipment, DEC was required to submit revised toxics modeling within 90 days of issuance of the wastewater treatment permit (also, see correspondence shown in the chronology). That modeling would then also apply to this (natural gas co-firing) application.

The revised toxics modeling and application addendum was received on March 18, 2019, to update the toxics modeling demonstration, revise the list of permitted sources, and update the insignificant activity list. The revised modeling applies to either one or both of the modeling demonstrations submitted with the applications for the new wastewater treatment facility and/or the natural gas co-firing project.

As a result of revised wind-erosion emission calculations, the potential particulate matter (PM) emissions from two material storage piles (I-1 coal pile and coal handling system and I-2 ash and ash handling system) are greater than the insignificant activities threshold. These storage piles are being moved from the IA list to the permit as ES-COALFUG and ES-ASHLFFUG respectively. DEC has requested revisions to the insignificant activities list including this and other changes. The addendum includes updated application forms, revised TAP emission calculations and an air dispersion modeling analysis with a facility-wide toxics pollutant emission rate analysis.

A description of the revisions to the facility-wide Toxic Pollutant Emission Rate (TPER) analysis is shown below. These revisions include the addition of sources previously omitted, updates to source parameter information, correction of hexavalent chromium emission sources, and revision to the emission calculation methodology for material storage piles.

Addition of Sources Previously Omitted
The following sources were added that were inadvertently omitted from the modeling demonstration:

- ES-FTLW1 and ES-FTLW2: Wet flyash truck loading equipment
- ES-TSU3&4: Flyash transfer silo, Unit 3&4
- I-139/I-144 (previously ES-FS1): Flyash transfer filter separator A/B for Units 1&2
- I-6: Gasoline, fuel oil, and kerosene pumps (note: the only existing pumps associated with this source are located at tank I-12 and I-13)
- I-12: 1,000 gallon above ground gasoline storage tank and associated unloading station
- I-13: 550 gallon above ground gasoline storage tank and associated unloading station (Mosquito Control Facility)

In addition, DEC has included emissions from 15A NCAC 02Q .0702 exempted sources (even though this is not a requirement), but that emit TAPs which are also associated with the new wastewater treatment system and natural gas co-firing projects. These additional sources include:

- I-7: 500,000 gallon above ground main No. 2 fuel-oil storage tank and associated unloading stations
- I-8: 30,000 gallon fuel oil storage tank at coal handling area
- I-84: 1,600 gallon above ground diesel fuel oil storage tank (emergency generator)
- I-85: 190 gallon above ground diesel fuel oil storage tank (emergency air compressor)
- I-127: 100 gallon above ground diesel fuel oil storage tank (emergency quench pump)
- I-129: 150 gallon above ground diesel fuel oil storage tank (emergency landfill generator)
- I-138: Wastewater treatment facility hydrochloric acid storage tank (10,000 gallon capacity)
- I-137: Landfill 200kW diesel emergency generator
- I-147: 400 gallon above ground diesel fuel oil storage tank (landfill 200 kW diesel emergency generator)

Updates to Source Parameter Information
As noted in the November 8, 2018 email correspondence with DAQ, DEC has corrected the base elevation of source “CCONV” (ES-CCONV2 through ES-CCONV8) from 253.3 to 235.3 meters.

Hexavalent Chromium Sources
As noted in the November 8, 2018 email correspondence, following submittal of both project applications, it was found that hexavalent chromium emissions had been incorrectly associated with several sources that do not emit this TAP. Therefore, DEC has revised the TPER analysis and modeling demonstration for this.

Material Storage Pile Wind Erosion Emission Calculation Methodology

As noted in the November 7, 2018 email correspondence, the DAQ questioned the methodology used to estimate and model wind erosion emissions from the storage piles. Specifically, DAQ indicated that hourly average wind speeds should not be used to estimate wind erosion emissions in conjunction with the methodology presented in US EPA AP-42 Section 13.2.5 on the basis that AP-42 is based on wind gust speed and not hourly average wind speed. Similarly, DAQ stated that hourly average wind speeds should not be used to limit wind erosion emissions within AERMOD using the "WSPEED" option. DAQ also questioned the area of piles used to estimate emissions and those used to model emissions in AERMOD.

Therefore, the wind erosion emission calculations were revised using Section 9.3 of the *WRAP Fugitive Dust Handbook* (dated September 7, 2006) and Table 21 of *Air / Superfund National Technical Guidance Study Series, Volume III – Estimation of Air Emissions from Cleanup Activities at Superfund Sites* dated January 1989 (EPA-450/1-89-003). These revised calculations use the material's silt content, the number of days with at least 0.01 inch of precipitation, and the percentage of time that the wind speed is greater than 12 miles per hour to estimate wind erosion emissions for PM/PM10/PM2.5.

To calculate the TAP emissions, the revised method multiplies the average hourly wind speed by a factor of 0.72 to estimate emissions (pounds per acre per hour). A conservative threshold velocity was used to limit emissions to periods of wind speeds greater than 11.3 miles per hour. Hourly emissions were calculated for each wind speed class available in AERMOD using the maximum velocity of each class. Emissions for class 6 were estimated using the maximum hourly average wind speed recorded during the years 2013 to 2017. Maximum hourly emissions were annualized using the number of hours spent in each class in each year. The worst-case year for TSP emissions was selected for the TPER analysis. Daily emissions were estimated by first calculating an uncontrolled emission factor for each hour of each year between 2013 and 2017 and then calculating a rolling sum for each 24-hour period. Finally, the maximum rolling 24-hour sum was identified and this maximum daily emission factor was applied to each storage pile incorporating the appropriate pile area and control efficiencies. Additional details and the revised emission calculation methodology are included in Attachment II of the application addendum.

DEC performed a facility-wide air toxics analysis, for all sources in the permit, including the new sources being added: three natural gas heaters, flare and vent for the natural gas line pigging operations, coal pile and coal handling, and ash landfills and ash handling. The highest potential to emit emissions rates for Units 1-4 over all of the operating scenarios were used in the modeling analysis and those emissions are the worst case for coal, fuel oil or natural gas. PTEs were also calculated and modeled for all other facility sources that emit any of the natural gas combustion pollutants that exceed the TPERs.

The modeling analysis was performed using the AERMOD computer dispersion model and five years of meteorological data (2013-2017) of surface meteorological data from the Charlotte Douglas International Airport (Station No. 13881) and upper-air sounding data also recorded at the Piedmont Triad International Airport in Greensboro, NC (Station No. 13723).

Dispersion modeling receptor grid was developed following procedures outlined in the *New Source Review Workshop Manual* (October 1990) and the revised *North Carolina Air Toxics Modeling Guidelines* (February 2014). A detailed discrete receptor grid system was created to assess air quality impacts in all directions to a distance of up to 10 kilometers from the Marshall Station. Discrete receptors were placed along the property line at 50-meter intervals. Receptors were also placed along the southern property boundary at a 25-meter grid spacing as there are emissions sources within 100 meters of the property boundary. The receptor grid then extends out from the property boundary to approximately 8 kilometers at increasing grid spacing of 100, 200, and 500-meters.

Air toxics emissions for the sources in this permit which are subject to a Part 63 MACT (e.g., the existing electric generating Units 1 - 4 subject to the utility MACT or MATS (Subpart UUUUU), existing engines ES-26, ES-35, ES-36 and ES-37 subject to the RICE MACT (Subpart ZZZZ), and the new natural gas supply line heaters ES-HTR1, ES-HTR2 and ES-HTR3 subject to the Industrial Boiler MACT (Subpart DDDDD)) are exempt from air permitting, pursuant to 02Q .0702(a)(27)(B). Nevertheless, the Permittee has included emissions for all such exempted sources in the modeling analysis.

The first step of the modeling analysis was to perform a facility-wide TPER analysis using potential emissions to determine if the TPERs in rule 02Q .0711 are exceeded for any toxic pollutant emitted.

The results of the TPER analysis indicates which toxic pollutants exceed their respective TPERs as shown in Table 7.

Next, for the following toxic pollutants exceeding their respective TPERs, potential emissions were modeled for comparison to the Acceptable Ambient Levels (AALs):

Ammonia (7664-41-7) – Hourly TPER exceeded
Arsenic And Inorganic Arsenic Compounds (ASC) – Annual TPER exceeded
Benzene (71-43-2)– Annual TPER exceeded
Benzo(a)pyrene (50-32-8) – Annual TPER exceeded
Beryllium (7440-41-7) – Annual TPER exceeded
Cadmium (7440-43-9) – Annual TPER exceeded
Ethyl Mercaptan (75-08-1) – Hourly TPER exceeded
Formaldehyde (50-00-0) – Hourly TPER exceeded
N-Hexane (110-54-3) – Daily TPER exceeded
Hydrogen Chloride (7647-01-0) – Hourly TPER exceeded
Hydrogen Sulfide (7783-06-04) – Daily TPER exceeded
Manganese (MNC) – Daily TPER exceeded
Mercury Vapor (7439-97-6) – Daily TPER exceeded
Nickel (7440-02-0) – Daily TPER exceeded
Soluble Chromate (VI) Compounds (SOLCR6) – Daily TPER exceeded

Table 8 shows the resulting modeled impacts for the baseline analysis. All pollutants are well below 100% of their respective AALs. Then, based on the resulting concentrations from the potential model run, the emission rates were then increased to an optimized rate such that modeled allowable emission rates result in ambient concentrations that are 98% of the AAL. Results for the optimized analysis are shown in Table 9 below. Optimizing the emission rates provides the Marshall Station with additional operational flexibility and should reduce the need for future TAP modeling analyses for these sources at the facility.

Table 7 - Toxic Pollutant Emission Rate (TPER) Analysis

Compound	Toxic Pollutant Emission Rates (TPER)				Marshall Steam Station Natural Gas Co-firing Modification							
	Acute Irritants	Acute Systemic Toxicants	Chronic Toxicants	Carcinogens	Acute Irritants		Acute Systemic Toxicants		Chronic Toxicants		Carcinogens	
	lb/hr	lb/hr	lb/day	lb/yr	lb/hr	Exceed TPER?	lb/hr	Exceed TPER?	lb/day	Exceed TPER?	lb/yr	Exceed TPER?
ARSENIC AND INORGANIC ARSENIC COMPOUNDS				0.053							175	**Yes**
BERYLLIUM				0.28							16.9	**Yes**
CADMIUM				0.37							215	**Yes**
MANGANESE AND COMPOUNDS			0.63						1.98	**Yes**		
MERCURY, VAPOR			0.013						0.321	**Yes**		
NICKEL METAL			0.13						1.69	**Yes**		
SOLUBLE CHROMATE COMPOUNDS, AS CHROMIUM (VI) EQUIVALENT			0.013						0.169	**Yes**		
AMMONIA	0.68				21.5	**Yes**						
BENZENE				8.10							430	**Yes**
BENZO(A)PYRENE				2.20							19.9	**Yes**
ETHYL MERCAPTAN		0.025					0.491	**Yes**				
P-DICHLOROBENZENE	16.8				0.0267	No						
FORMALDEHYDE	0.04				7.92	**Yes**						
N-HEXANE			23.0						1410	**Yes**		
HYDROGEN CHLORIDE	0.18				17.5	**Yes**						
HYDROGEN SULFIDE			1.7						19.6	**Yes**		
TOLUENE	14.4		98.0		0.284	No			6.81	No		

Table 8 – Summary of Baseline Modeling Analysis

Compound	Year	Averaging Period	Maximum Concentration (μg/m³)	AAL (μg/m³)	Percent of AAL (%)
Ammonia	2013	1-hour	210.3	2700	7.79
Arsenic	2017	Annual	0.00027	0.0021	12.86
Benzene	2015	Annual	0.0152	0.12	12.7
Beryllium	2015	Annual	0.0000714	0.0041	1.74
Benzo(a)pyrene	2016	Annual	0.00000732	0.033	0.022
Cadmium	2016	Annual	0.0000888	0.0055	1.62
Chromium VI	2013	24-hour	0.00117	0.62	0.189
Ethylene Mercaptan	2014	1-hour	17.8	100	17.8
Formaldehyde	2015	1-hour	1.13	150	0.75
n-Hexane	2013	24-hour	349.0	1100	31.7
Hydrogen Chloride	2015	1-hour	85.2	700	12.2
Hydrogen Sulfide	2016	24-hour	63.3	120	52.8
Manganese	2013	24 hour	0.0162	31	0.052
Mercury	2013	24 hour	0.000412	0.6	0.069
Nickel	2014	24 hour	0.00709	6	0.118

Table 9 – Summary of Optimized Modeling Analysis

Compound	Year	Averaging Period	Maximum Concentration (μg/m³)	AAL (μg/m³)	Percent of AAL (%)
Ammonia	2013	1-hour	2,648	2700	98
Arsenic	2017	Annual	0.00206	0.0021	98
Benzene	2015	Annual	0.117	0.12	98
Beryllium	2015	Annual	0.00401	0.0041	98
Benzo(a)pyrene	2016	Annual	0.032	0.033	98
Cadmium	2016	Annual	0 .00539	0.0055	98
Chromium VI	2013	24-hour	0.608	0.62	98
Ethylene Mercaptan	2014	1-hour	97.9	100	98
Formaldehyde	2015	1-hour	147	150	98
n-Hexane	2013	24-hour	1,078	1100	98
Hydrogen Chloride	2015	1-hour	687	700	98
Hydrogen Sulfide	2016	24-hour	117	120	98
Manganese	2013	24 hour	30.3	31	98
Mercury	2013	24 hour	0.586	0.6	98
Nickel	2014	24 hour	5.88	6	98

DEC's toxics dispersion modeling analysis was approved by Matthew Porter, AQAB, (see memo to Ed Martin dated April 18, 2019). The air toxics modeling analysis of facility-wide TAP emissions adequately demonstrated compliance with AALs outlined in 15A NCAC 02D. 1104, on a source-by-source basis.

No toxics monitoring is required since the potential emissions are significantly below the optimized emissions, which demonstrates compliance with the AALs as shown in Tables 8 and 9.

Detailed toxic emission calculations are presented in DEC's March 2019 application addendum Appendix A.

The permit toxic limits for all sources modeled, except for the MACT sources, which are exempt from toxics permitting, are shown below in Table 10 and in permit condition 2.2.B.1.a. A TPER limit condition is added at Section 2.2.B.2 for p-dichlorobenzene and toluene since these TPERs were not exceeded.

Table 10
Permit Toxic Emission Limits

Emission Source ID No.	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
ES-6 (RUL) ES-6a (RULa) ES-6b (RULb) ES-7 (LUBFA) ES-8(LUBFB)	Arsenic and Inorganic Arsenic Compounds	2.20E-02	-	-
	Beryllium	1.74E-02	-	-
	Cadmium	3.63E-02	-	-
	Manganese and compounds	-	8.47E-01	-
	Mercury Vapor	-	6.85E-05	-
	Nickel Metal	-	1.59E-02	-
ES-9 (LCB1)	Arsenic and Inorganic Arsenic Compounds	2.20E-02	-	-
	Beryllium	1.74E-02	-	-
	Cadmium	3.63E-02	-	-
	Manganese and compounds	-	8.47E-01	-
	Mercury Vapor	-	6.85E-05	-
	Nickel Metal	-	1.59E-02	-
ES-11 (LCB2)	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-
F1	Arsenic and Inorganic Arsenic Compounds	3.04E+00	-	-
	Beryllium	2.40E+00	-	-
	Cadmium	5.01E+00	-	-
	Manganese and compounds	-	1.17E+02	-
	Mercury Vapor	-	9.47E-03	-
	Nickel Metal	-	2.20E+00	-
ES-12a (LPR)	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-
ES-12b (LCB3)	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-

Emission Source ID No.	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
ES-14 (LCB4)	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-
ES-16 (LCB5)	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-
ES-18a (LCB6a)	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-
ES-18b (ELBE) ES-18c (LCB6c) ES-20 (S1LCB7) ES-21 (S2LCB8) ES-22 (LS1) ES-23 (LS2)	Arsenic and Inorganic Arsenic Compounds	3.15E-02	-	-
	Beryllium	2.49E-02	-	-
	Cadmium	5.19E-02	-	-
	Manganese and compounds	-	1.21E+00	-
	Mercury Vapor	-	9.80E-05	-
	Nickel Metal	-	2.28E-02	-
ES-S1 ES-FTLD1	Arsenic and Inorganic Arsenic Compounds	8.48E+00	-	-
	Beryllium	9.22E+00	-	-
	Cadmium	1.24E+00	-	-
	Soluble Chromate Compounds, as Chromium (VI) Equivalent	-	3.37E-01	-
	Manganese and compounds	-	1.63E+01	-
	Mercury Vapor	-	4.01E-03	-
	Nickel Metal	-	3.13E+00	-
ES-S2ES-FTLD2	Arsenic and Inorganic Arsenic Compounds	8.48E+00	-	-
	Beryllium	9.22E+00	-	-
	Cadmium	1.24E+00	-	-
	Soluble Chromate Compounds, as Chromium (VI) Equivalent	-	3.37E-01	-
	Manganese and compounds	-	1.63E+01	-
	Mercury Vapor	-	4.01E-03	-
	Nickel Metal	-	3.13E+00	-

Emission Source ID No.	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
ES-FTLW1 ES-FTLW2	Arsenic and Inorganic Arsenic Compounds	1.38E-02	-	-
	Beryllium	1.50E-02	-	-
	Cadmium	2.02E-03	-	-
	Soluble Chromate Compounds, as Chromium (VI) Equivalent	-	5.46E-04	-
	Manganese and compounds	-	2.64E-02	-
	Mercury Vapor	-	6.49E-06	-
	Nickel Metal	-	5.08E-03	-
ES-CCONV2 ES-CCONV6 ES-CCONV7 ES-CCONV8	Arsenic and Inorganic Arsenic Compounds	1.56E-01	-	-
	Beryllium	2.97E-01	-	-
	Cadmium	3.61E-02	-	-
	Manganese and compounds	-	3.05E-01	-
	Mercury Vapor	-	1.16E-03	-
	Nickel Metal	-	1.05E-01	-
ES-TSU3&4	Arsenic and Inorganic Arsenic Compounds	1.48E+00	-	-
	Beryllium	1.61E+00	-	-
	Cadmium	2.17E-01	-	-
	Soluble Chromate Compounds, as Chromium (VI) Equivalent	-	5.88E-02	-
	Manganese and compounds	-	2.84E+00	-
	Mercury Vapor	-	6.99E-04	-
	Nickel Metal	-	5.47E-01	-
ES-PIGGING	Ethyl Mercaptan	-	-	2.71E+00
	n-Hexane	-	5.46E+03	-
ES-WWTF Silo	Arsenic and Inorganic Arsenic Compounds	4.35E-03	-	-
	Beryllium	4.56E-03	-	-
	Cadmium	7.47E-03	-	-
	Manganese and compounds	-	8.18E-02	-
	Mercury Vapor	-	1.17E-05	-
	Nickel Metal	-	3.28E-03	-
ES-WWTFBR	Hydrogen Sulfide	-	3.64E+01	-
ES-COALFUG	Arsenic and Inorganic Arsenic Compounds	1.78E+02	-	-
	Beryllium	3.40E+02	-	-
	Cadmium	4.13E+01	-	-
	Manganese and compounds	-	3.49E+02	-
	Mercury Vapor	-	1.33E+00	-
	Nickel Metal	-	1.20E+02	-
ES-ASHLFFUG	Ammonia	-	-	1.31E+01
	Arsenic and Inorganic Arsenic Compounds	1.07E+03	-	-
	Beryllium	1.16E+03	-	-
	Cadmium	1.56E+02	-	-

Emission Source ID No.	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
	Soluble Chromate Compounds, as Chromium (VI) Equivalent	-	4.23E+01	-
	Manganese and compounds	-	2.04E+03	-
	Mercury Vapor	-	5.03E-01	-
	Nickel Metal	-	3.94E+02	-
I-6	Benzene	5.73E+00	-	-
	n-Hexane	-	5.60E-03	-
I-12	Benzene	2.88E+01	-	-
	n-Hexane	-	2.83E-02	-
I-13	Benzene	1.58E+01	-	-
	n-Hexane	-	1.55E-02	-
I-33	Ammonia	-	-	3.76E-01
I-72	Arsenic and Inorganic Arsenic Compounds	2.04E+00	-	-
	Cadmium	4.07E+00	-	-
	Manganese and compounds	-	1.38E+02	-
	Mercury Vapor	-	8.74E-02	-
	Nickel Metal	-	1.02E+00	-
I-86	Arsenic and Inorganic Arsenic Compounds	1.07E-03	-	-
	Beryllium	8.46E-04	-	-
	Cadmium	1.76E-03	-	-
	Manganese and compounds	-	4.12E-02	-
	Mercury Vapor	-	3.33E-06	-
	Nickel Metal	-	7.74E-04	-
I-139 / I-144	Arsenic and Inorganic Arsenic Compounds	1.24E+00	-	-
	Beryllium	1.34E+00	-	-
	Cadmium	1.81E-01	-	-
	Soluble Chromate Compounds, as Chromium (VI) Equivalent	-	4.91E-02	-
	Manganese and compounds	-	2.37E+00	-
	Mercury Vapor	-	5.83E-04	-
	Nickel Metal	-	4.57E-01	-

In addition, a permit TPER limit condition for benzo(a)pyrene, P-dichlorobenzene and toluene was added to the permit in Section 2.2.D.1.b.

2. **One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-1) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-1c (U1SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-2), electrostatic precipitator (ID No. CD-3), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U1/2FGD)**

   One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-2) and associated selective non-catalytic reduction system

(SNCR) NOx reduction system (ID No. CD-4c (U2SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-5), electrostatic precipitator (ID No. CD-6), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U1/2FGD)

One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-3) and associated selective catalytic reduction system (SCR) NOx reduction system (ID No. CD-7c (SCR)), electrostatic precipitator (ID No. CD-9 (ESPnew)), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U3FGD)

One No. 2 fuel oil/natural gas/coal-fired electric utility boiler equipped with a low NOx concentric firing system, separated overfire air/lowered fired low-NOx technologies (SOFA/LOFIR), and alkaline-based fuel additive (ID No. ES-4) and associated selective non-catalytic reduction system (SNCR) NOx reduction system (ID No. CD-11c (U4SNCR)), sulfur trioxide flue gas conditioning system (ID No. CD-12), powdered activated carbon system (ID No. CD-U4ActC), electrostatic precipitator (ID No. CD-13 (ESPnew)), and wet flue gas desulfurization system consisting of spray tower absorber (ID No. CD-U4FGD)

Three natural gas-fired, natural gas supply line heaters (ID Nos. ES-HTR1, ES-HTR2 and ES-HTR3)

Natural gas supply line pigging operation including fugitive emissions from pig receiver vent (ID No. ES-PIGGING) with associated temporary flare of natural gas from supply line (ID No. CD-PIG FLARE)

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
Pursuant to 15A NCAC 02Q .0501(b)(2) or (c)(2), for completion of the two-step significant modification process initiated by Application No. (1800073.18B), the Permittee shall file an amended application following the procedures of Section 15A NCAC 02Q .0500 within one year from the date the first of these sources (ID Nos. ES-1 through ES-4, ES-HTR1, ES-HTR2, ES-HTR3 or ES-PIGGING) begins to burn natural gas.

VI. Public Notice

Public notice is not required at this time.

VII. Other Requirements

PE Seal
The D5 form for technical portions of the application was sealed by Amy M. Marshall, PE, Seal No. 027844 on September 28, 2018 pursuant to 15A NCAC 02Q .0112.

Zoning
A Zoning Consistency Determination form was received October 26, 2018, signed by Chris Temberlake, Catawba County Planning and Parks, stating that the application had been received and that the proposed operation is consistent with applicable zoning ordinances.

Fee Classification
The facility fee classification before and after this modification will remain as “Title V”.

Increment Tracking
Catawba County has triggered increment tracking under PSD for PM10. However, this permit modification does not consume or expand increments for any pollutants since the potential lb/hr rates when burning 100% coal will not change.

VIII. Comments on Draft Permit

Comments from DEC

The draft permit and review were sent to Ann Quillian at DEC on April 22, 2019 for review. Duke responded on April 29, 2019 with the following comments.

1. DEC requested a footnote be added to the table of permitted emission sources in Section 1 for the Units 1-4 electrostatic precipitators and FGD systems as follows:

   While operating on only natural gas, the electrostatic precipitator and the FGD may be operated intermittently as necessary, based on boiler system requirements, to maintain compliance with applicable emission standards.

   DAQ Response
   Added this as footnote ****.

2. DEC requested removal of Subpart BBBBB "CSAPR NOx Ozone Season Trading Program" from the 40 CFR Part 97 Cross-State Air Pollution Rule (CSAPR) permit requirements for the four boilers (ID Nos. ES-1 thru ES-4) in Section 2.1.A.8, as North Carolina is not subject to this requirement.

   DAQ Response
   Subpart BBBBB was removed.

Comments from MRO and SSCB

The draft permit and review were sent to Samir Parekh with Stationary Source Compliance Branch and Melinda Wolanin at the Mooresville Regional Office on April 22, 2019 for review. No comments were received.

IX. Recommendations

Issuance is recommended.