NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date:

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300383
Inspector's Name: Melinda Wolanin
Date of Last Inspection: 02/08/2022
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Kings Mountain Energy Center

Facility Address:
Kings Mountain Energy Center
181 Gage Road
Kings Mountain, NC 28086

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, 0515, .0516, .0521, .0400, .0524, .0530, .0614, .1100, .1111
NSPS: IIII, KKKK, TTTT
NESHAP: GACT ZZZZ
PSD: YES
PSD Avoidance: NO
NC Toxics: YES
112(r): NO
Other: 02Q .0400, Acid Rain Procedures

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Matthew Hickey EHS Manager (410) 459-9594 181 Gage Road Kings Mountain, NC 28086	T. J. Higgins Vice President - Asset Management (919) 747-5056 801 Corporate Center Drive, Suite 116 Raleigh, NC 27607	Matthew Hickey EHS Manager (410) 459-9594 181 Gage Road Kings Mountain, NC 28086

Application Data

Application Number: 2300383.19B, 15A
Date Received: 07/30/2019, 06/11/2015
Application Type: Modification
Application Schedule: TV-1st Time ; Title IV

Existing Permit Data

Existing Permit Number: 10400/R03
Existing Permit Issue Date: 08/12/2019
Existing Permit Expiration Date: 03/31/2023

Total Actual emissions in TONS/YEAR:

CY	SO_2	NOX	VOC	CO	PM10
2020	6.03	61.50	21.10	12.33	0.6400
2019	6.17	57.85	21.85	7.59	0.5700
2018	2.72	65.71	9.54	95.22	0.3000
2017	---	0.1800	---	0.0500	0.0100

Review Engineer: Joseph Voelker

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

Comments / Recommendations:
Issue 10400/T04
Permit Issue Date:
Permit Expiration Date:

I. Introduction and Purpose of Application

Kings Mountain Energy Center (KMEC), located in Kings Mountain, North Carolina currently holds air permit no. 10400R03 with an expiration date of March 31, 2023.

KMEC has submitted the following two applications:

Application No. 2300383.19B
As stated in the application cover letter, KMEC is submitting its initial title V permit application. The first day of commercial operation of the facility was August 9, 2018; accordingly, this application was submitted within the 12-month deadline required by the current operating permit and North Carolina Division of Air Quality (NC DAQ) regulations.

The 12-month deadline referenced above is addressing the following condition inserted into the initial air permit (permit revision R00) issued April 15, 2015, at Section 2.2 B.5:

> The Permittee shall file a Title V Air Quality Permit Application pursuant to 15A NCAC 2Q .0504 on or before 12 months after commencing operation.

The application was received July 30, 2019, within the 12-month deadline.

The initial application (permit revision R00) was processed under the North Carolina state permitting regulations 15A NCAC 02Q .0300, “Construction and Operation Permits” and 15A NCAC 02D .0530, “Prevention of Significant Deterioration,” the regulation that implements the federal New Source Review permitting program in areas that meet all of the National Ambient Air Quality Standards.

No physical modifications are being proposed in this current application. However, the current permit will be revised to contain emission limitations and associated testing, monitoring, recordkeeping and reporting requirements consistent with the Title V of the Clean Air Act operating permitting program as implemented pursuant to the North Carolina regulations found at 15A NCAC 02Q .0500, “Title V Procedures.”

Application No. 2300383.15A
Additionally, an acid rain permit application (Title IV of the Clean Air Act) was received on June 11, 2015, as required by the existing permit condition at Section 2.1 A.5. The application is being consolidated into this initial TV permit application. This application will be processed consistent with the requirements in both NCAC 02Q .0400 and .0500, the implementing regulations for Title IV and Title V respectively, and satisfy all applicable public participation, and EPA and affected states review requirements.

II. Chronology

Date	Description
06/11/2015	An acid rain permit application was received, assigned Application No. 2300383.15A and deemed administratively complete by the DAQ. Application included a Certificate of Representation for the designated representative. Application placed on hold until receipt of the initial TV application.
07/30/2019	The 1st time Title V application was received, assigned Application No. 2300383.19B and deemed administratively incomplete by the DAQ. An application acknowledgment letter was sent stating that two more copies were needed to deem the application administratively complete.
09/09/2019	Additional copies of the application were received as requested on 07/30/2019. Application deemed administratively complete.
10/07/2021	An email was received from Jeffery Connors of AECOM, consultant for the Permittee. The email presented the issue of using partial operating hours consistent with 40 CFR Part 60 requirements to demonstrate compliance with the PSD NOx and CO emission limits during startup and shutdown.
11/17/2021	An email from Matthew Hickey, EHS manager, was received stating” *Based on the table, we are calculating the limit to fall under the first standard, output standard 1,000 lb CO_2/MWh. However, that standard may change based on operation, we determine the standard annually per the “Affected EGU” description. Would it be possible to write the permit in such a way that it just*

Date	Description
	references the table so that we would not need to potentially modify the permit in the event of operational changes, hence the CO_2 *emission standard would then potentially change in the future.* See NSPS Subpart TTTT discussion in section VI.A below.
11/30/2021	An email was received from Jeffery Connors of AECOM, consultant for KMEC. The email presented a potential solution to the issue raised in the email received on 10/07/2021.
12/6/2021	Joe Voelker of the DAQ sent an email to the Permittee proposing an alternate solution to the solution proposed by the Permittee in the 11/30/2021 email.
12/7/2021	An email was received from Jeffery Connors of AECOM, consultant for KMEC. The email stated the approach presented by the DAQ in the 12/6/2021 email would serve as a practical solution to address the partial operating hour issue during startups and shutdowns first raised in the 10/07/2021 email.
12/7/2021	Joe Voelker of the DAQ sent an email to KMEC. The email requested that the responsible official submit an email requesting that the solution proposed on 12/06/2021 be incorporated into the TV permit.
12/14/2021	An email was received from T.J. Higgins the responsible official. Mr. Higgins requested the monitoring approach proposed by the DAQ on 12/6/2021 be incorporated into the TV permit.
04/11/2022	Draft sent to KMEC for review
06/14/2022	First set of comments received from KMEC
06/15/2022	A response to the comments received on 06/14/2022 was sent to KMEC. A revised draft was also sent incorporating the comments as necessary.
07/12/2022	Second set of comments in response to the revised draft permit sent on 06/15/2022 was received via email. The only comment was associated with the missing data substitution procedures that were not included in the existing permit but were added to the proposed draft permit during this initial TV permitting process. The DAQ took the comments under consideration and decided to not include the missing data procedures in the proposed draft permit.
~~MM/DD/YYYY~~	~~Public Notice published on NCDENR DAQ website and in the newspaper XXYXYX; concurrent public/EPA comment period begins~~
~~MM/DD/YYYY~~	~~Public comment period ends. TBD~~
~~MM/DD/YYYY~~	~~EPA comment period ends. TBD~~

III. Modification Description

As stated in Section I above, the purpose of this permitting action is to subject the facility's current permit to the requirements of the federal Title V of the Clean Air Act operating permitting program as implemented pursuant to the North Carolina regulations found at 15A NCAC 02Q .0500, "Title V Procedures" and to issue an Acid Rain Permit pursuant to 15A NCAC 02Q .0400. No physical modifications are proposed in these applications.

The permit review for the initial permit R00 contains an exhaustive regulatory review for the facility as it was proposed to be built. The permit was revised three times since then, each time a thorough regulatory review for the changes made was conducted. See Section IV below for an outline of the permitting history for this facility.

In this initial TV application, the Permitee has supplied a package of revised forms and calculations that reflect the current configuration of the plant, which is simply a compilation of the initial application and the three permit revisions since that time.

Since this initial TV application does not propose any physical changes to the facility as it is currently permitted, the previous permit reviews (e.g., statements of basis) will be leveraged to avoid redundancy. Discussion in this review document will primarily address any requirements that are not adequately covered in the previous permit review documents. The previous permit review documents will be included as attachments to this review document.

Each source or group of sources will be discussed in Section VI below.

IV. Complete Permitting History

A summary for the permitting history of the facility is provided below. Language contained is excerpted from the original application reviews. The reviews (i.e., statements of basis) for each of these modifications are included as appendices to this review document.

Permit No.	Issue Date	Application No.	Application type
R03	08/12/2019	19A	State- Modification

As stated in the application….

NTE Carolinas, LLC (NTE) is submitting this permit application to modify certain condition in the Kings Mountain Energy Center's (KMEC) operating permit pertaining to ammonia emissions.

First, the facility is requesting removal of an emission limit that was erroneously established as Best Available Control Technology in the Prevention of Significant Deterioration (PSD) permit issued for initial construction and operation of the KMEC facility.

Second, NTE is requesting an increase in the permitted allowable emission rate for ammonia associated with compliance with the North Carolina toxic air pollutant (TAP) regulations.

Permit No.	Issue Date	Application No.	Application type
R02	01/10/2019	18B	State- Modification

As stated in the application….

NTE Carolinas, LLC (NTE) owns the Kings Mountain Energy Center (KMEC), a natural gas fired combined-cycle power plant, permitted under North Carolina Department of Environmental Quality (NCDEQ Air Quality Permit No. 10400R01. NTE respectfully requests an Air Quality Modification (Minor Permit Change pursuant to 15A NCAC 02Q .0300 to clarify that emission limits for the Combustion Turbine (CT) during startup operations are based on a 3-hour average, as presented in the PSD Permit Application No. 2300386.14A that resulted in the issuance of Air Quality Permit No. 10400R01 (the "Permit Application"). This proposed modification does not result in an increase of the startup event emissions or duration on a per event basis, as described in the Permit Application.

Permit No.	Issue Date	Application No.	Application type
R01	01/16/2018	17A	State- Modification

As stated in the application….

NTE Carolinas, LLC (NTE) is constructing, and will operate, a natural gas-fired combined-cycle power plant known as the Kings Mountain Energy Center (KMEC or Facility). KMEC is located at 181 Gage Road near the City of Kings Mountain in Cleveland County, North Carolina. The Facility received a Prevention of Significant Deterioration (PSD) Air Quality Permit (No. 10400R00) in April of 2015 (Facility ID: 2300383).

The original PSD construction permit application included a 138 million Btu per hour (MMBtu/hr) Auxiliary Boiler (ES-2) and an 1,850-brake horsepower (bhp) Emergency Generator (ES-4). NTE is proposing to install an auxiliary boiler and emergency generator that are smaller than what NTE applied for in the construction permit application.

The current PSD permit limits the Diesel Emergency Generator (ES-4) and Diesel-fired Emergency Fire Pump (ES-5) to 30 minutes per hour of non-emergency operation. Additionally, the permit does not allow ES-4 and ES-5 to operate simultaneously. These limits do not provide adequate working time for commissioning of the engines. It is requested that during initial commissioning of these engines, the diesel emergency generator be allowed to operate up to 40 hours and the emergency fire pump be allowed to operate up to 30 hours. The commissioning tests of the engines will only be conducted when the Combustion Turbine (CT) and Auxiliary Boiler at the facility are not operating. Therefore, the commissioning tests are not expected to impact results of NAAQS compliance modelling submitted and approved with the PSD permit application.

Permit No.	Issue Date	Application No.	Application type
R00	04/15/2015	14A	Greenfield-PSD

As stated in the application….

NTE Carolinas, LLC (NTE) is proposing to construct and operate a natural gas-fired combined-cycle power plant to be known as the Kings Mountain Energy Center (KMEC or Project). The Project will be located near the City of Kings Mountain in Cleveland County, North Carolina (Project Site). The Project will consist of a single power block in a “1x1” combined-cycle multi-shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). The CT and ST will each have separate electric generators. NTE is requesting an Air Quality Permit to Construct/Operate for the following equipment configuration, provided by Mitsubishi Hitachi Power Systems Americas (MHPSA):

- MHPSA M501GAC CT in a 1 x 1 combined-cycle configuration.

A duct burner (DB) will be installed in the HRSG of the proposed new unit. The CT and duct burner will fire pipeline-quality natural gas. The HRSG will be equipped with selective catalytic reduction (SCR) to minimize nitrogen oxide (NOx) emissions and oxidation catalysts to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CT and DB.

The Project will also include several pieces of ancillary equipment.

V. Facility Emissions Review

The emission sources and associated control devices as represented in the draft permit are as follows. Note there are also insignificant activities and fugitive emission sources not listed in this table.

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-1	One (1) nominal 475 Megawatt (MW) natural gas-fired combined-cycle combustion turbine with duct burner (max. heat input = 2,945 million Btu per hour CT only and 3,603 million Btu per hour CT + DB). CT equipped with dry low-NOx combustors.	CD-1A	Selective catalytic reduction (SCR)
		CD-1B	oxidation catalyst (*formerly CO oxidation catalyst**)
ES-2	Natural gas-fired auxiliary boiler with low NOx burners (42.8 million btu per hour maximum heat input)	NA	NA
ES-3	Natural gas-fired fuel gas heater (9 million btu per hour maximum heat input)	NA	NA
ES-4	Diesel fuel-fired standby emergency generator (1,528 maximum brake horsepower)	NA	NA
ES-5	Diesel fuel-fired emergency fire pump engine (260 maximum brake horsepower)	NA	NA
ES-6	Multi-cell cooling tower (175,000 gallon per minute maximum recirculating flow rate)	CD-6	Mist eliminator (0.0005 percent drift loss)

*This descriptor was revised during this permitting action. See discussion at Section VI.F, Item 8 below.

The following table is based on Appendix C Table 17 of the current application. The table below presents potential emissions of each source after controls and any emissions or operating limitations. Note this list includes sources of facility-wide fugitive emissions of greenhouse gases (GHGs) which are not associated with any specific emission source.

Emission Unit	NOX	CO	VOC	SO2	PM10	PM2.5	H2SO4	Pb	GHGs (CO2e)	Total HAPs
Combustion Turbine w/ Duct Burner	103.4	243.2	86.9	26.5	65.4	65.4	20.3	0.004	1,676,538	6.6
Diesel Engine-Powered Emergency Generator	3.10	0.22	0.02	0.005	0.03	0.03	4.62E-04	2.5E-05	449	4.70E-03
Diesel Engine-Powered Fire Pump	0.43	0.17	0.017	0.001	0.021	0.02	1.02E-04	4.0E-06	75	1.80E-03
Auxiliary Boiler	0.94	3.17	0.43	0.05	0.60	0.60	2.00E-02	4.2E-05	10,218	0.16
Dew Point Heater	0.43	3.15	0.20	0.08	0.28	0.28	9.66E-03	1.9E-05	4,705	0.07
Cooling Tower					2.44	0.008				
Lubricating Oil Vents			0							
Diesel and Lubricating Oil Tanks			0.0021							
Natural Gas Piping Fugitives									73	
Natural Gas Maintenance + SU/SD Venting									168	
SF6 Circuit Breakers									132.8	
Total Project Emissions	**108.3**	**249.9**	**87.6**	**26.7**	**68.8**	**66.4**	**20.4**	**0.004**	**1,691,985**	**6.9**
Major Source Threshold	100	100	100	100	100	100	100	100	100,000	10/25
Major Source?	Yes	Yes	No	No	No	No	No	No	Yes	No
PSD Significant Net Emission Rate	40	100	40	40	15	10	7	0.6		
Subject to PSD Review?	Yes	Yes	Yes	No	Yes	Yes	Yes	No	Yes	

As expected, the combustion turbine by far is the largest contributor to all pollutant's emissions totals.

Regarding hazardous air pollutants (HAPs) regulated under Section 112 of the Clean air Act (CAA), the facility is an area source of HAP with a PTE of less than 25 tpy total HAP/10 tpy individual HAP. Based on Table C-12 of the current application the PTE for total HAP is 6.67 tons per year. The HAP with the largest PTE is formaldehyde at 2.5 tpy, followed by toluene at 1.7 tpy and then acetaldehyde at 0.52 tpy.

Regarding toxic air pollutants (TAPs) which are regulated under the North Carolina state enforceable only regulations at 15A NCAC 02Q .0700 and 02D .1100, the TAPs with the largest PTEs are ammonia at 43.8 tpy, sulfuric acid at 20.4 tpy and formaldehyde (which is both a HAP and TAP) at 2.5 tpy.

As stated in Section III above, this permitting action does not involve any physical changes to the facility and will not result in any changes to the potential or actual emission estimates of the facility.

VI. Regulatory Review

All sources, or groups of sources with similar regulatory applicability, are discussed individually below. Each section includes a brief description of the emission sources. Any substantial changes to the permit conditions will be included in Section IX, "Changes Implemented in Revised Permit."

A. Regulations applicable to the following sources:

Emission Source ID No.	Emission source Description	Control Device ID No.	Control Device Description
ES-1	One (1) nominal 475 Megawatt (MW) natural gas-fired combined-cycle combustion turbine with duct burner (max. heat input = 2,945 million Btu per hour CT only and 3,603 million Btu per hour CT + DB). CT equipped with dry low-NOx combustors.	CD-1A	Selective catalytic reduction (SCR)
		CD-1B	CO oxidation catalyst

This emission source consists of a combustion turbine (CT), heat recovery steam generator (HRSG) equipped with a duct burner (DB) and a steam turbine (ST). Only the CT and DB involve combustion and hence the generation of pollutants. It is also worth noting that KMEC is not planning (nor has it requested) to operate the HRSG and ST independently of the CT. Thus, to simplify the discussion, this aggregated emission source will be referred to as CT. Specific mention to the various components will be made as necessary.

The combined-cycle combustion turbine / heat recovery steam generator (CT/HRSG) package incorporates an advanced CT model M501GAC from MHPSA that is similar in design and performance to the current generation commercially available or under development by MHPSA's major competitors. For purposes of developing worst-case emission rates and stack parameters and conducting the required regulatory compliance demonstrations, control technology evaluations, and air quality impact analyses used in the initial air permit application (permit revision R00), NTE obtained performance and emissions data for the MHPSA M501GAC CT in combined-cycle configuration. All required demonstrations were performed using the worst-case emissions and other specifications from the CT model.

In the combined-cycle process, ambient air is drawn into the compressor element of the CT through an inlet air filtration and silencing system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity to further enhance overall production capability of the CT. After the evaporative cooler section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion stage of the CT. This section of the CT is commonly referred to as the gas generator section. The gas generator is the component that generates criteria and hazardous air pollutant emissions by means of the fuel combustion process.

A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion products (hot gases) expand through the stages of the power turbine where the thermodynamic, or gas energy is converted to mechanical power.

This power is transmitted through rotation of the shaft to the generator for the CT, which is directly coupled to the turbine. The generator takes this rotative power and converts it to electricity.

The hot gases produced in the CT are directed into the HRSG through an exhaust transition duct where waste heat is converted into steam energy before the exhaust gases exit the vertical stack for the HRSG. The HRSG contains the natural gas fired duct burners (DB) that will be used at times to increase the temperature of the exhaust gases in the HRSG. This is done to maximize output of the steam cycle in the plant.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once the steam does its work in the ST, it is exhausted and condensed at a vacuum in the steam surface condenser. The cycle is a closed loop system as the condensate is reused as feed water to the HRSG. Circulating cooling water from the cooling tower is used to condense the steam in the condenser.

The CT/HRSG is designed to operate up to 8,760 hours per year at 100 percent load firing natural gas, which will be the exclusive fuel used in this equipment. The CT is not expected to operate less than 75 percent of base load for significant periods of time. The DB is also designed for exclusive natural gas firing and typically is operated only when the CT is at 100 percent load.

15A NCAC 2D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS

This regulation applies to particulate matter emissions from the combustion of fuel in indirect heat exchangers (IDHXs) that are discharged from any stack or chimney into the atmosphere. The emission limitation for a given IDHX is determined as a function of the total heat input to all IDHXs on site at the time the particular IDHXs was permitted.

This rule limits PM emissions from fuel burning heat exchangers by the following equation:

$E = 1.090*(Q)^{(-0.2594)}$
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

For purposes of this rule, there are three fuel burning indirect heat exchangers at the site:

Auxiliary boiler (see Section VI.B below) –	42.8 MMBtu/hr
Fuel gas heater (see Section VI.B below) –	9 MMBtu/hr
Heat recovery steam generator with duct burner (HRSG + DB)	<u>704 MMBtu/hr</u>
Total heat input from all on site IDHXs =	755.8 MMBtu/hr

Using the equation above, the allowable PM emission rate from each of these sources is: 0.20 lb/MMBtu (two significant digits, consistent with the rule). Note that the heat input associated with the CT, which is not an IDHX, is not included in the analysis. Since there is only one stack however, the CT PM emissions will be commingled with the regulated PM emissions (HRSG+DB). Therefore, this emission limit does not apply to the CT/HRSG/DB when the DBs are not operational. As a result, the existing permit contains the following caveat: “This emission limitation only applies when the duct burner is in operation.”

As a result of the best available control technology (BACT) analyses for ES-1 conducted under prevention of significant deterioration (PSD) in the original PSD application (permit revision R00), the following BACT limits for particulate matter apply to the CT/HRSG/DB:

0.0041 lb/MMBtu, CT only
0.0059 lb/MMBtu, CT + DB

Thus, the 02D .0530 PSD BACT limits are two orders of magnitude more stringent than the 0.20 lb/MMBtu limit derived here pursuant to 02D .0503. The BACT emission limitations will be enforced through the 02D .0530 PSD permit conditions (see Section VI.F below for additional information). Given the expected margin of compliance with respect to the PM emission limit under 02D .0503, no monitoring, recordkeeping, and reporting pursuant to 02D .0503 will be required.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
This rule applies to all fuel burning sources and industrial processes reasonably expected to have visible emissions. Visible emissions from sources constructed after July 1, 1971, shall not be more than 20 percent opacity when averaged over a six-minute period. Visible emissions from the combustion of natural gas are inherently low and therefore are expected to be well below 20% opacity. Consistent with current DAQ policy, no testing, monitoring, recordkeeping, and reporting will be required for the firing of natural gas in the combined-cycle combustion turbine.

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS
(40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines)

40 CFR Part 60 Subpart KKKK (NSPS KKKK) applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu per hour based on the higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005. The peak load heat input rate of the CT (2,945 million Btu per hour without the heat input of DBs) is much greater than the 10 MMBtu/hr applicability threshold. Therefore, the CT/HRSG/DB (ID No. ES-1) is subject to this regulation. Pursuant to 60.4305, although only the heat input associated with the CT is used for applicability purposes, the emissions from the HRSG duct burners(DBs) are subject to this rule.

This rule has been revised (October 7, 2020) since the drafting of the existing permit condition in the initial permit (permit revision R00) issued April 15, 2015. However, the changes to the rule were minimal and only affected 40 CFR 60.4415, which addresses initial and subsequent performance testing for sulfur. The rule was revised to allow fuel sulfur specification documentation to be used to demonstrate compliance. This change does not affect the existing permit condition as the monitoring requirements at 60.4365(a) to ensure compliance have already been implemented. The requirements at 40 CFR 60.4365(a) provide for an alternative to fuel sulfur content monitoring and are effectively the same as those included in the revised 40 CFR 60.4415(a).

NSPS KKKK has requirements for two pollutants, NOx and SO_2.

Emission Limits for NOx
Pursuant to 40 CFR 60.4320 and Table 1 of NSPS KKKK, the CT/HRSC/DB (ID No. ES-1) is subject to an emission standard of 15 ppm at 15 percent O_2, when fired with natural gas. If the turbine operates at partial load (less than 75 percent of peak load) or if the turbine operates at temperatures less than 0ºF, a NOx limit of 96 ppm at 15 percent O_2 will apply.

KMEC has chosen to comply with the concentration-based NOx emission standards. Note that the permit also contains BACT NOx limits to pursuant to 02D .0530 (PSD) (See Section 2.1 A.4). The BACT limits are the CT/HRSC/DB will reduce its NOx emissions to 2 ppm at 15 percent O_2 on a 1-hour basis using low-NOx combustors and selective catalytic reduction while exclusively burning natural gas. Therefore, compliance with the more stringent BACT NOx emission limits is expected to result in compliance with the NSPS KKKK limits.

KMEC demonstrates compliance with the NSPS NOx emission limits via continuous monitoring with NOx CEMS. The rule effectively requires the calculation of hourly emission "rates" (ppm is allowed and are the units of the standard chosen by KMEC), but excess emissions are assessed on a "30-unit operating day rolling average basis." To date there have been no compliance issues associated with compliance with these standards. The NOx CEMS, as they readily calculate the hourly averages, are also used to demonstrate compliance with the BACT NOx emissions limits pursuant to 02D .0530.

Emission Limits for SO_2
Pursuant to 40 CFR 60.4330(a), the CT/HRSC/DB (ID No. ES-1)will be subject to an emission limit of 0.9 lb/MWh gross output, or the turbines must not burn any fuel which contains the total potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu heat input.

KMEC has chosen to comply with the heat input-based emission standard for SO_2. The CT and the HRSG duct burners will burn only natural gas. Using the application supplied sulfur estimate for natural gas of 0.7 grains sulfur/100 ft3 sulfur content and approximately 1,023 Btu/ft3 (HHV) heat content for natural gas, the SO_2 emission rate for the CT is estimated as 0.002 lb/MMBtu. Therefore, compliance is expected with the SO_2 emission limits by a wide margin while firing natural gas, which is the only fuel permitted for the CT/HRSG/DB. Based on DAQ inspection reports the facility is demonstrating compliance with pipeline supplied records of sulfur content sampling.

Other requirements

The current permit contains notification requirements for date of construction, actual start up and date of performance tests. Based on a DAQ inspection report these dates were reported as July 22, 2015, for date of construction and January 10, 2018, for actual startup. The facility notified the DAQ of the performance test on February 9, 2018. The facility had performed initial stack testing on July 16-19, 2018. The current permit will be revised to remove these completed notification requirements.

In the existing permit the only reporting requirement was for the CEMS excess emissions and monitoring systems performance report required pursuant to 40 CFR 60.4395 and 60.7(c). As allowed pursuant to 40 CFR 60.7(c) and to be consistent with the DAQs Stationary Source Compliance Branch (SSCB) policy ("Legal Basis for Calculation and Reporting Frequencies of CEMS/COMs -affected Facilities," October 27, 2020) for these types of reports, the calculations required pursuant to 40 CFR 60.7(c) and (d) shall be on a quarterly basis. The semiannual reporting frequency will remain unchanged.

Pursuant to the DAQ Title V reporting requirements under 15A NCAC 02Q .0508, a permit shall require semiannual reporting of required monitoring. Fuel sulfur records are required for SO_2 monitoring purposes. Therefore, a reporting requirement for a summary of the fuel sulfur records is being added to the draft permit.

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS

(40 CFR Part 60 Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units)

40 CFR Part 60 Subpart TTTT (NSPS TTTT) applies to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014, or commenced reconstruction or modification after June 18, 2014, that meets the following applicability requirements at 40 CFR 60.5509(a)(1) and (2) (paraphrased):

> (1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel); and
> (2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The combustion turbine (CT) (ID No. ES-1) was constructed after January 8, 2015, meets these applicability requirements and is therefore subject to this rule. This rule was promulgated on October 23, 2015, which was after the issuance date of the initial permit (permit revision R00). The existing permit does not contain a condition that addresses this rule.

Pursuant to 40 CFR 60.5520 the CT is potentially subject to one or more of the three GHG emissions standards for CTs in Table 2 to NSPS TTTT. As the CT only burns natural gas only the two following standards are potentially applicable.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that **supplies more than its** design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales **on both** a 12-operating month **and** a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh).
Newly constructed or reconstructed stationary combustion turbine that **supplies its** design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales **on either** a 12-operating month **or** a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).

The first standard, the energy output-based standard, applies to units colloquially referred to as "base load" units, as they sell a significant portion of their potential electric output. The second standard, the heat input-based standard, applies to "non-base load" units.

For base load units, the rule requires the following to meet the energy output-based standard:

- The preparation of a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/hr), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h).
- The calculation of the hourly CO_2 mass emissions from the affected EGU according to 40 CFR 60.5535(c).
- The installation, calibration, maintenance, and operation of a sufficient number of watt meters to continuously measure and record the hourly gross electric output from the affected EGU meeting the requirements of 40 CFR 60.5535(d)(1).
- Associated monitoring, recordkeeping, notification and reporting requirements.

In contrast, for non-base load units, the rule requires only the following to meet the heat input-based standard:

- KMEC shall keep purchase records of natural gas
- Associated monitoring, recordkeeping, notification and reporting requirements.

Note the compliance obligations are substantially greater for the EGUs required to comply with the output-based standard.

KMEC, via an email received November 17, 2021 (see section II above) stated it is currently subject to the output-based standard but would like the flexibility to comply with input-based standard if in the future it meets the applicability criteria as presented in Table 2 of NSPS Subpart TTTT without going through the TV significant modification permitting process. To accomplish this, consistent with permit content and operating scenario requirements specified in 15A NCAC 02Q .0508(b) and (j) and the General Provisions of 40 CFR Part 60, specifically 60.10, "State Authority," the permit was modified to be structured as follows:

- Section 2.1 A.4 will require KMEC to submit a permit applicability determination request, consistent with 15A NCAC 02Q .0111, and receive approval from the DAQ to change its compliance obligations from Section 2.1 A.5 (i.e., base load unit requirements) to Section 2.1 A.6 (i.e., non-base load unit requirements). This section will also require KMEC to submit a notification to the DAQ if it chooses/needs to switch back to the base load unit requirements.
- Section 2.1 A.5 will contain all compliance obligations for the CT while meeting the applicability requirements for base load units.
- Section 2.1 A.6 will contain all compliance obligations for the CT while meeting the applicability requirements for non-base load units.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
See discussion under Section VI.F, "Facility-Wide Emission Sources" below.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
No MACT rules apply. See discussion in Section VII below.

15A NCAC 02D .1400 NITROGEN OXIDES
Amendments to the following rules became effective May 1, 2022:

- 15A NCAC 02D .1401 "Definitions" – the definitions for "EGU", "Large non-EGU", and "NOx ozone season budget" were added to the list of definitions.
- 15A NCAC 02D .1402 "Applicability" - It was revised to include the new rules 15A NCAC 02D .1424 and .1425 to the list of rules that apply statewide.

The following new rules were adopted by the DAQ and became effective May 1, 2002:

- 15A NCAC 02D .1424 "Large Non-Electric Generating Units" – It includes an option for large non- electric generating units (EGUs) to request alternative monitoring for determining NOx emissions during the ozone season if they are not required to monitor NOx for another rule.
- 15A NCAC 02D .1425 "NOx SIP Call Budget" - It includes the NOx ozone season budgets for EGUs and large non-EGUs and to require reporting of the NOx emissions to the DAQ for the ozone season.

As a result of these changes, a revised applicability analysis of the 02D .1400 rules needs to be conducted at this time. Note at the time of the initial permit issuance (permit revision no. R00 issued on April 15, 2015), no 02D .1400 rules were applicable to any sources at KMEC pursuant to 15A NCAC 02D .1402(a) as it was written at that time. The following background narrative is provided to add explanation for these newly applicable requirements.

<u>Background</u>
(The following discussion was excerpted from the "Regulatory Impact Analysis for Revisions to the Monitoring Provisions for the NOx SIP Call" conducted by Carrie Pickett and Bradley Nelson of the DAQ Rules Development Branch. It was included in the docket for the 02D .1400 rules that were amended or adopted and effective as of May 1, 2022)

The U.S. Environmental Protection Agency (EPA) issued the NOx SIP Call on October 27, 1998 (63 FR 57356). The NOx SIP Call was designed to assist areas in attaining the 1979 1-hour ozone National Ambient Air Quality Standards (NAAQS) by reducing the transport of ozone and precursor emissions from upwind states. The EPA developed a cap and trade system for NOx emissions referred to as the Federal NOx Budget Trading Program (NBTP). The NBTP was codified in 40 Code of Federal Regulations (CFR) Part 97*.

In 2002, the DAQ established requirements for a NOx cap and trade program involving both the EGU and non-EGU sources. These requirements were codified in the DAQ rules under 15A NCAC 2D .1400. The rule included NOx allocations for each affected source and a total state budget along with a demonstration that North Carolina would achieve the required emission reductions in accordance with timelines set forth in the state's SIP. As part of demonstrating compliance, these sources had to install and operate a CEMS or other approved monitoring methods under the EPA's 40 CFR Part 75 monitoring requirements.

A new federal NOx and sulfur dioxide (SO2) trading program, called the Clean Air Interstate Rule (CAIR), was promulgated by the EPA in 2005, which replaced the previous NOx SIP Call budget trading program. The CAIR was promulgated to address transport under both the 1997 8-hour ozone and PM2.5 NAAQS. States could choose to implement annual and ozone season NOx reductions through this federal allowance trading program. North Carolina chose to comply by participating in the federal allowance trading program and by "opting-in" non-EGU sources into the program. The CAIR requirements and budgets for the non-EGUs were identical to the NOx SIP Call, and were codified in the DAQ rules under 15A NCAC 2D .2400 in July of 2006.

In subsequent years, the CAIR was remanded without vacatur by the D.C. Circuit, and replaced with the EPA's Cross-State Air Pollution Rule (CSAPR) on August 8, 2011 (76 FR 48208). The CSAPR requires states to improve air quality by reducing EGU emissions crossing state lines and contributing to both ozone and fine particle pollution in other states starting initially in 2012, but implementation did not begin until 2015. The non-EGUs were excluded from the CSAPR NOx budget trading program because the EPA concluded that these sources did not reduce NOx emissions as a result of being included in the previous trading programs and that these sources, as a group, had allowances they did not need for compliance. The first set of emissions requirements under the CSAPR took effect on January 1, 2015. The CAIR provisions expired on February 1, 2016 as a result of the DAQ's periodic review and expiration of existing rules (G.S. 150B-21.3A).

Although the non-EGU sources have no federal requirements to monitor or reduce emissions under the CSAPR, the EPA has stated that the anti-backsliding provisions of 40 CFR 51.905(f) require the provisions of the NOx SIP Call, including the statewide NOx emission budgets for non-EGUs, be maintained. Furthermore, the requirements of the NOx SIP Call continue to be permanent and enforceable, including all state regulations developed to implement the requirements of the NOx SIP Call (77 FR 45259). In a very brief "frequently asked questions" (FAQ) document posted on the agency's CSAPR web site, titled "NOx SIP Call Transition for Large non-EGUs", the EPA states that:
(1) CSAPR does not preempt or replace the requirements of the NOx SIP Call,
(2) NOx SIP Call budgets remain in place for non-EGUs, and
(3) 40 CFR Part 75 monitoring, recordkeeping and reporting requirements must be retained.

*The EPA also issued regulations for states to implement a NOx Budget Trading Program at 40 CFR Part 96 as the "NOx Budget Trading Program for State Implementation Plans."

Revised 02D .1400 applicability analysis

15A NCAC 02D .1402: APPLICABILITY
The rules in 02D .1400 do not apply except as specifically set out in this rule. The requirements in this section only apply from May 1 to September 30 of each year. KMEC is located in Cleveland County. As KMEC is not located in one of the counties identified in paragraph (e) of this rule, the only potentially applicable rules under 02D .1400 are the following rules (or specific sections of the rules) as indicated in paragraph (c) of this rule:

- 15A NCAC 02D .1409(c): STATIONARY INTERNAL COMBUSTION ENGINES
- 15A NCAC 02D .1418: NEW ELECTRIC GENERATING UNITS, BOILERS, COMBUSTION TURBINES, AND I/C ENGINES
- 15A NCAC 02D .1423: LARGE INTERNAL COMBUSTION ENGINES

- 15A NCAC 02D .1424: LARGE NON-ELECTRIC GENERATING UNITS
- 15A NCAC 02D .1425: NOX SIP CALL BUDGET

Each rule will be discussed separately below.

15A NCAC 02D .1409(c): STATIONARY INTERNAL COMBUSTION ENGINES
This rule at paragraph(c) identifies engines at three specific facilities which does not include KMEC. Thus, this rule does not apply to KMEC.

15A NCAC 02D .1418: NEW ELECTRIC GENERATING UNITS, BOILERS, COMBUSTION TURBINES, AND I/C ENGINES
The source (ID No. ES-1) is an EGU and a combustion turbine, was permitted after October 1, 2000, and serves a generator with a nameplate capacity greater than 25 megawatts electrical and sells electricity. As such it meets the applicability requirements at 02D .1418(a).

KMEC is required to comply with paragraph (a)(2) which states:

> (2) if regulated by 15A NCAC 02D .0530, meet the best available control technology requirements in 15A NCAC 02D .0530 or 0.15 pounds per million Btu for gaseous and solid fuels and 0.18 pounds per million Btu for liquid fuels, whichever requires the greater degree of reduction;

The CT is subject to a BACT limit under 02D .0530 that is more stringent than 0.15 lb/million Btu. The BACT limit is 2 ppmvd @ 15%O2, which is approximately equivalent to 0.008 lb/million Btu.

Paragraph (d) requires:

> (d) Monitoring. The owner or operator of a source subject to this Rule, except for internal combustion engines, shall show compliance using a continuous emission monitor that meets the requirements of 15A NCAC 02D .1404(d). Internal combustion engines shall comply with the monitoring requirements in 15A NCAC 02D .1423. Monitors shall be installed before the first ozone season in which the source will operate and shall be operated each day during the ozone season that the source operates.

02D .1404(d) requires:

> (d) Continuous emissions monitors.
> (1) The owner or operator shall install, operate, and maintain a continuous emission monitoring system according to 40 CFR Part 75, Subpart H, with such exceptions as may be allowed under 40 CFR Part 75, Subpart H or 40 CFR Part 96 if the source is covered by 15A NCAC 02D .1418, with the exception of internal combustion engines.

Thus, pursuant to 15A NCAC 02D .1418, KMEC must comply with the BACT limit using a NOx CEMs according to 40 CFR Part 75Subpart H.

It will be shown below in the regulatory discussion for Cross State Air Pollution Rule (CSAPR; 40 CFR Part 97) that the CT is also subject to the CSAPR NOx annual trading program at 40 CFR Part 97 Subpart AAAAA. 40 CFR 97.430 requires:

> 97.430 General monitoring, recordkeeping, and reporting requirements.
> The owners and operators, and to the extent applicable, the designated representative, of a CSAPR NOX Annual unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart <u>and subpart H of part 75 of this chapter</u>.

Thus, pursuant to both CSAPR Subpart AAAAA and 02D .1418, the NOx CEMS will need to meet the requirements of 40 CFR Part 75 Subpart H.

With respect to reporting, 40 CFR Part 75 Subpart H at 40 CFR 75.73(d) states:

> d) General reporting provisions.
> (1) The designated representative for an affected unit shall comply with all reporting requirements in this section and with any additional requirements set forth in an applicable State or federal NOx mass emission reduction program that adopts the requirements of this subpart.

02D .1418 does not specifically address any reporting requirements (additional or otherwise), including the reporting requirements of 40 CFR Part 75 Subpart H. As discussed above, 02D .1404(d) via 02D .1418(d) requires the "owner or operator shall install, operate, and maintain a continuous emission monitoring system according to 40 CFR Part 75 Subpart H." It is assumed then that to "install, operate, and maintain" means to comply with all requirements for the NOx CEMS under Subpart H unless specified otherwise.

The reporting requirements under Subpart H, among other things, include ongoing quarterly reporting. The requirements include the reporting of

- Average NOx emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NOx emission rate for the calendar year.
- Tons of NOx emitted during quarter, cumulative tons of NOx emitted during the year, and, during the second and third calendar quarters, cumulative tons of NOx emitted during the ozone season.

This ongoing reporting pursuant to Subpart H is also done electronically to the Administrator, which is not the DAQ. In short, the reporting requirements in Subpart H do not include reporting that specifically supports the determination of compliance by the DAQ with the BACT limits via the use of the NOx CEMs as required by 02D .1418. Therefore, for purposes of 02D .1418, and consistent with DAQ policy for sources that use CEMS to determine compliance, semiannual reporting pursuant to 15A NCAC 02Q .0508(f) consisting of an excess emissions and monitoring systems performance report containing the information required in 40 CFR 60.7(c) and (d) will be required. The emissions and monitoring system performance results shall be calculated on a quarterly basis consistent with current DAQ policy.

15A NCAC 02D .1423: LARGE INTERNAL COMBUSTION ENGINES
No sources at KMEC meet any of the applicability requirements under this rule. Thus, this rule does not apply to KMEC.

15A NCAC 02D .1424: LARGE NON-ELECTRIC GENERATING UNITS
No sources at KMEC meet any of the applicability requirements under this rule. Thus, this rule does not apply to KMEC.

State-enforceable only
15A NCAC 02D .1425: NOX SIP CALL BUDGET
Pursuant to 15A NCAC 02D .1401 "Definitions," the CT (ID No. ES-1) meets the definition of a "EGU."

Pursuant to 02D .1425(b), KMEC must submit a report to the DAQ no later than January 30 of the calendar year after the NOx SIP Call control period listing the NOx emissions from the CT (ID No. ES-1) during the NOx SIP Call control period. The NOX SIP control period is defined under 02D .1401 as:

> "NOx SIP Call control period" for the purposes of the NOx SIP Call budgets in 15A NCAC 02D .1425 means the period May 1 through the end of September 30.

The NOx emissions in this report shall be determined in accordance with 40 CFR Part 75 for EGUs and large non-EGUs subject to 15A NCAC 02D .1418, or in accordance with 15A NCAC 02D .1424 for large non-EGUs using alternative monitoring. Thus, the CT, which is subject to 15A NCAC 02D .0418, shall determine its NOx emissions in accordance with Part 75. Note that the CT, which is subject to 02D .1418 discussed above, and CSAPR Subpart AAAAA discussed below, is required to determine its NOx emissions as well as meet the monitoring recordkeeping and reporting requirements consistent with 40 CFR Part 75 Subpart H. Thus the electronic report being submitted to the EPA electronically quarterly will now also be submitted to the DAQ once per year.

A permit condition will be placed into the permit to address this rule. As the rule has not been incorporated into the state implementation plan (SIP), it will be considered state enforceable only.

15A NCAC 02Q .0400: ACID RAIN PROCEDURES
(40 CFR Parts 72 and 76)

North Carolina air quality regulation 15A NCAC 02Q .0400 implements the Phase II of the federal acid rain program, pursuant to Title IV of the CAA, as provided in 40 CFR Parts 72 and 76. Part 76 applies to coal -fired units, which does not apply here. 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. SO_2 allowances are not allocated by US EPA for new units under 40 CFR Part 73; however, the sources must hold enough SO_2 allowances to cover their annual SO_2 emissions. There are no NOx emission limits for gas or oil-fired units.

The existing permit (No. R03) contains a requirement for the submittal of a complete Acid Rain permit application at least 24 months before the date on which the unit (ID No. ES-1) commences operation. The unit commenced operation on August 9, 2018, and the Acid Rain Permit (ARP) application was received June 11, 2015. The DAQ deemed this application "complete" for purposes of both Title IV and Title V of Clean Air Act (CAA) effective August 9, 2018. The DAQ will process this application consistent with the requirements in both 15A NCAC 02Q .0400 and .0500, the implementing regulations for Title IV and Title V respectively, and satisfy all applicable public participation, and EPA and affected states review requirements.

The combustion turbine (ID No. ES-1) is an affected, fossil-fuel fired "new" unit (i.e., commenced commercial operation on or after November 15, 1990), with a capacity to produce electricity of equal to or more than 25 MW for sale. Therefore, the unit is subject to Acid Rain program requirements in 02Q .0400.

40 CFR 72.73(b)(2) requires that each Acid Rain permit issued in accordance with this program shall have a term of 5 years commencing on its effective date. By consolidating the ARP application with the initial TV application, both the ARP and the TV permit will have the same effective and expiration dates. Pursuant to 40 CFR 72.32, the timely and complete ARP application serves effectively as an ARP until the permitting authority (i.e., the DAQ) issues the ARP.

40 CFR Part 72 requires the installation, certification, operation, and maintenance of continuous emissions or opacity monitoring systems pursuant to 40 CFR Part 75. For the CT (ID No. ES-1) KMEC must monitor and report SO_2 mass emissions, NO_x emission rate, CO_2 mass emissions and heat input. In the cover letter for the acid rain application KMEC states it will use a NO_x and O_2 CEMS, calculate SO_2 emissions based on fuel certifications, calculate CO_2 emissions in accordance with Appendix G of Part 75 and calculate heat input using an Appendix D of Part 75 certified fuel flow meter.

Although the DAQ is considered the "permitting authority," the "Administrator" is still the US EPA. Most of the oversight of the ARP is handled directly between the designated representative and the US EPA.

The proposed draft TV permit will include a specific section (Section 2.3) to address the ARP requirements. The ARP application, which includes all the general requirements under the ARP program, will be included as an attachment to the combined Title IV and Title V permit. KMEC must comply with the standard requirements and special provisions included in the attached application.

Cross State Air Pollution Rule (CSAPR; 40 CFR Part 97)

CSAPR requires fossil fuel-fired electric generating units at coal-, gas-, and oil-fired facilities in 27 states in the eastern US to reduce emissions to help downwind areas attain fine particle and/or ozone national ambient air quality standards (NAAQS).

CSAPR requirements have been promulgated to address interstate transport for the 2006 24-hour fine particulate NAAQS, 1997 annual fine particulate NAAQS, 1997 8-hour ozone NAAQS, and 2008 ozone NAAQS, resulting in the creation of several air quality-assured trading programs for states in the CSAPR region:

The CSAPR NOx annual trading program;	Subpart AAAAA
The CSAPR NOx ozone season Group 1 trading program;	Subpart BBBBB
The CSAPR SO_2 Group 1 trading program;	Subpart CCCCC
The CSAPR SO_2 Group 2 trading program;	Subpart DDDDD
The CSAPR NOx ozone season Group 2 trading program	Subpart EEEEE

CSAPR is implemented in NC by the US EPA directly as a Federal Implementation Plan (FIP). 40 CFR 52.1784 indicates the FIP requirements for NOx, which references Subparts AAAAA and BBBBB, and 40 CFR 52.1785 indicates the FIP requirements for SO_2, which references Subpart CCCCC.

40 CFR 52.1784 was revised October 26, 2016 (as described in the Federal Register (FR) at 81 FR 74504 and 74599) to only require compliance with Subpart BBBBB with regard to emissions occurring in 2015 and 2016. These FR references describe basically that NC does not contribute significantly to nonattainment in or interference with maintenance of the 1997, 2005 or 2015 ozone standards for any other states. Therefore, North Carolina is currently only subject to the NOx annual trading program (Subpart AAAAA) and the SO_2 group 1 trading program (Subpart CCCCC). This conclusion is documented by EPA on their website (See the EPAs webpage "States that are affected by CSAPR" at https://www.epa.gov/csapr/overview-cross-state-air-pollution-rule-csapr).

As CSAPR is not addressed in North Carolina's State Implementation plan (SIP) no state rules apply. In general, CSAPR requires tracking and trading emission credits across multiple facilities, including facilities not within the state of North Carolina. Oversight of the CSAPR is managed directly by the US EPA.

Consistent with current NC Title V permitting policy, a permit condition will be placed into the draft TV permit containing a reference to the applicable subparts of the CSAPR (Subparts AAAAA and CCCCC) but no specific compliance requirements will be included.

B. Regulations applicable to the following sources:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-2	Natural gas-fired auxiliary boiler with low NOx burners (42.8 million Btu per hour maximum heat input)	NA	NA
ES-3	Natural gas-fired fuel gas heater (9 million Btu per hour maximum heat input)	NA	NA

The auxiliary (aux) boiler was originally permitted in the initial permit (permit revision R00) with a heat input of 138 MMBtu/hr. The aux boiler ultimately installed had a heat input of 42.8 MMBtu/hr. This change was addressed in Application No. 2300383.17A and resulted in the issuance of Permit No. 10400R01 on January 16, 2018. The auxiliary boiler is natural gas-fired and operates as needed to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine during warm and hot starts. Operation of the auxiliary boiler is limited to 4,000 hours of operation per year.

The natural gas-fired fuel gas heater will operate as necessary to condition the natural gas prior to combustion to prevent condensation. The maximum rated capacity of the fuel gas heater is 9 MMBtu/hr and can be operated for 8,760 hours per year at its maximum capacity.

Maximum criteria and HAP emissions for these sources are estimated based on vendor-supplied information, AP-42 emission factors, and natural gas fuel specifications. See summary of emissions in Section V of this review.

15A NCAC 2D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
As discussed in Section VI.A above, this regulation applies to particulate matter emissions from the combustion of fuel in IDHX that are discharged from any stack or chimney into the atmosphere. The emission limitation for a given IDHX is determined as a function of the total heat input to all IDHX on site at the time the particular IDHX was permitted.

The PM emission limit that applies to these IDHXs (ID Nos. ES-2 and 3) applies to all IDHXs on site. Thus, the derivation discussion in Section VI.A. above applies to these boilers as well. As derived in Section VI. A. above, the allowable PM emission rate for each of these boilers is 0.20 lb/MMBtu.

Based on the original BACT analyses for the boiler and fuel gas heater in the initial permit application (permit revision R00), KMEC has the following BACT emission limitations for PM (See Section IV above):

Auxiliary boiler -	0.007 lb/MMBtu
Fuel gas heater –	0.007 lb/MMBtu

These emission limitations are enforced through the PSD permit conditions (See Section VI.F below). Given the expected margin of compliance, no additional monitoring, recordkeeping and reporting with respect to 02D .0503 will be required. No substantive changes will be made to the existing permit condition that addresses this regulation.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
This regulation applies to any combustion source that emits sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances 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. Based on the AP-42 emission factor for natural gas combustion of 0.60 lb/10^6 scf or 5.88E-04 lb/MMBtu, SO_2 emissions from the combustion of natural gas are expected to be well below these allowable limits. Consistent with current DAQ policy, no testing, monitoring, recordkeeping and reporting will be required.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
This rule applies to all fuel burning sources and industrial processes reasonably expected to have visible emissions. Because the auxiliary boiler and fuel gas heater were constructed after 1971, visible emissions from these sources shall not be more than 20

percent opacity when averaged over a six-minute period. Visible emissions from the combustion of natural gas are inherently low and therefore are expected to be well below 20% opacity. Consistent with current DAQ policy, no testing, monitoring, recordkeeping and reporting will be required.

15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS
(40 CFR Part 60 Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)

Pursuant to 40 CFR 60.40c, with some exceptions this rule applies to:

> ***each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989, and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

The auxiliary boiler (ID No. ES-2) has a maximum design heat input greater than or equal to 10 MMBtu/h. The natural gas-fired fuel gas heater has a maximum design heat input less than 10 MMBtu/h. Thus, only the boiler meets the applicability criteria and is therefore subject to this rule.

Because it has a heat input greater than 10 MMBtu/hr and only burns natural gas, this boiler is only subject to initial startup notification requirements (40 CFR 60.48c(a)) and monthly fuel usage recordkeeping requirements (40 CFR 60.48c(i)). Initial notification of the actual start-up of boiler was March 23, 2018, completed April 09, 2018.

The Permit will be revised to remove the notification requirement since this date has passed, but the monthly fuel recordkeeping requirements will remain.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR Part 63, Subpart DDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters)

This rule affects facilities that are major sources of HAP. As the facility is a minor source of HAP, this rule does not apply.

(40 CFR Part 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources)

This rule affects facilities that are area sources of HAP.

The auxiliary boiler (ID No. ES-2) is defined as a gas-fired boiler, which is specifically exempted from this subpart in accordance with 40 CFR 63.11195(e). Since it is not permitted to burn other fuels which have requirements under this rule, no potential compliance issues are expected and hence no monitoring, recordkeeping and reporting is necessary to ensure compliance with this rule. No further review is necessary.

The fuel gas heater (ID No. ES-3) is defined as a process heater pursuant to 40 CFR 63.11237. As a process heater , the fuel gas heater is excluded from the definition of a boiler as defined at 40 CFR 63.11237. Since only boilers are considered affected sources pursuant to 40 CFR 63.11194, this rule does not apply to the fuel gas heater. No further review is necessary.

<u>State Enforceable Only</u>
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion under Section VI.F, "Facility-Wide Emission Sources" below.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion under Section VI.F, "Facility-Wide Emission Sources" below.

C. The following engines:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-4	Diesel fuel-fired standby emergency generator (1,528 maximum brake horsepower)	NA	NA

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-5	Diesel fuel-fired emergency fire pump engine (260 maximum brake horsepower)	NA	NA

The fire water pump engine (ID No. ES-5) will be used for emergency purposes in the event of a fire and for routine operations and testing as required by the National Fire Prevention Association (NFPA) Code. The emergency diesel fire pump is rated at a maximum 260 brake HP.

The emergency diesel engine powered standby generator (ID No. ES-4) , rated at 1,528 maximum brake horsepower, allows maintenance of vital plant loads during power outages or maintenance on the switchyard.

The diesel engine generator and fire pump are operated during power interruptions to provide emergency power, lighting, and fire protection when the combustion turbine is not operating and at most once per week for less than 30 minutes for operational testing purposes when the CT is operational.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
This regulation applies to any combustion source that emits sulfur dioxide (SO_2) formed by the combustion of sulfur in fuels, wastes, ores, and other substances 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.

However, pursuant to 15A NCAC 02D .0516(b), this Rule does not apply to sources already subject to an emission standard for SO_2 in 15A NCAC 02D .0524 (i.e., NSPS). Both of the engines are subject to NSPS under 40 CFR Part 60 Subpart IIII (implemented via 15A NCAC 02D .0524) which contains a fuel sulfur limitation which effectively serves as an emission standard for SO_2. Therefore 02D .0516 does not apply to these sources. No further discussion is necessary.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
This rule applies to all fuel burning sources and industrial processes reasonably expected to have visible emissions. Visible emissions from these engines constructed after 1971, shall not be more than 20 percent opacity when averaged over a six-minute period. Visible emissions from the combustion of diesel fuel are expected to be well below 20% opacity. Consistent with current DAQ policy, no testing, monitoring, recordkeeping and reporting will be required.

15A NCAC02D .0524: NEW SOURCE PERFORMANCE STANDARDS (NSPS)
(40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)

This rule applies to the compression ignition (CI) internal combustion engines (ICE) at KMEC: the emergency fire pump engine and the emergency standby generator. The rule requires manufacturers of such engines to meet emission standards that are phased in for the size, type of engine application, and model year of the engine. The owners and operators of affected engines are required to configure, operate, and maintain the engines according to specifications and instructions provided by the engine manufacturer and to maintain records demonstrating compliance. The rule requires KMEC to purchase emergency engines certified by manufacturers to meet the applicable emissions standards. The KMEC engines must meet the ultra-low sulfur content standard of 15 ppm. Operation for emergency purposes is not restricted but is restricted to 100 hours per year for non-emergency purposes. The emergency engines must install an hour-meter and track hours of operation in emergency and non-emergency service and keep the associated records as well as records of maintenance.

Based upon the most recent inspection, KMEC has purchased the proper certified engines and has been keeping all the appropriate records. The current permit contains a separate condition for each engine. Given the requirements are similar, the existing conditions will be consolidated into one permit condition in the draft TV permit.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines)

This rule applies to stationary reciprocating internal combustion engines (RICE) at area (non-major) and major sources of HAP emissions. The KMEC facility is an area source of HAP emissions. This rule applies to the emergency fire pump engine and the emergency standby generator as they are both RICE.

In accordance with 40 CFR 63.6590(c), new or reconstructed compression ignition engines at area sources must meet the requirements of 40 CFR Part 60, Subpart IIII to comply with requirements of Subpart ZZZZ. No other requirements apply under Subpart ZZZZ.

The existing permit contains a permit condition that indicates that compliance with the applicable requirements of NSPS IIII will indicate compliance with Subpart ZZZZ. This will remain unchanged in the revised permit.

15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion under Section VI.F, "Facility-Wide Emission Sources" below.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion under Section VI.F, "Facility-Wide Emission Sources" below.

D. The following emission source:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-6	Multi-cell cooling tower (175,000 gallon per minute maximum recirculating flow rate)	CD-6	Mist eliminator (0.0005 percent drift loss)

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once the steam does its work in the ST, it is exhausted and condensed at a vacuum in the steam surface condenser. The cycle is a closed loop system as the condensate is reused as feed water to the HRSG. Circulating cooling water from the cooling tower is used to condense the steam in the condenser.

The cooling towers are equipped with mist eliminators and operate continuously when the CT is operated. The cooling towers emit small amounts of PM emissions associated with wet cooling tower drift losses. Drift loss will be minimized with high-efficiency drift eliminators.

15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES
This PM emission standard applies when no other PM standard applies. This source is subject to a PM BACT standard implemented via 02D .0530, "Prevention of Significant Deterioration." Thus, this rule does not apply.

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
This rule applies to all fuel burning sources and industrial processes reasonably expected to have visible emissions. Visible emissions from sources constructed after 1971 shall not be more than 20 percent opacity when averaged over a six-minute period. Cooling towers are sources of PM emissions and hence potentially visible emissions. However, the visible emissions are primarily the result of the water droplets themselves. EPA Reference Method 9 is used to determine compliance with visible emission limitations (expressed as a percent opacity). The method provides for opacity determination "beyond the point in the plume at which condensed water vapor is no longer visible."

Based on the actual performance of other cooling towers, the opacity as determined by Method 9 is expected to be essentially 0%. Therefore, consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required, and no substantial changes are necessary to the existing permit.

E. Insignificant activities

The current permit application (Form A2) contains reference to the following insignificant activities considered to be insignificant based on size or production rate pursuant to 15A NCAC 02Q .0503(8).

- I-1 Lube Oil Storage
- I-2 5,000 Gallon Diesel Storage Tank

See discussion below for these and other potential insignificant sources.

<u>I-1 Lube Oil Storage</u>
On Form B of the current permit application, it states that this source is a "lubricating oil sump with a system capacity of 15,000 gallons." In the original application (permit revision R00) it also states:

the combustion turbine and the steam turbine are also be equipped with lubricating oil vents, which include electrostatic precipitators/demisters for lubricating oil mist control. Use of low-volatility/low-VOC oil and low consumption rate of lubricating oil in the CT and ST will result in insignificant VOC emissions from these sources.

The source will be included in the insignificant list as follows:

- I-1 Lube Oil Storage System (15,000 gallon capacity)

See discussion of emissions and regulatory review below.

I-2 and I-3 Diesel Fuel Storage Tanks

In the original application narrative (permit revision R00) it states that a 5000-gallon diesel storage tank will be located on site to supply diesel fuel for the two diesel engines. In addition, a 300-gallon day tank will be used for the diesel fire water pump. Fuel will be transferred from storage to the day tank and the diesel fire water pump will take suction directly from the day tank. See discussion of day use tank below.

The sources will be included in the insignificant list as follows:

- I-2 Diesel Fuel Storage Tank (5,000 gallon capacity)
- I-3 Fire Pump Engine Diesel Fuel Day Use Tank (300 gallon capacity)

See discussion of emissions and regulatory review below.

Insignificant sources emissions discussion

VOC emissions were estimated for all of the tank storage operations using EPA's Tanks 4.0.9d program. Estimated annual potential VOC emissions from the tanks are summarized in Table 3-8 reproduced from Permit Application No.2300383.14A below.

Table 3-8 – Potential Emissions from Diesel and Lubricating Oil Storage Tanks

Tank ID/Description	Volume (gal)	TANKS 4.0.9d VOC Emissions (TPY)
Diesel storage tank	5,000	<0.001
Fire Pump Engine Diesel Day Tank	300	<0.001
Lubricating Oil Tank 1	15,000	<0.0001
Total		**0.002**

Clearly, VOC emissions from each of these tanks are well below 5 tpy and meet the definition of insignificant activity based on size or production rate pursuant to 15A NCAC 02Q .0503(8).

Other tanks not considered emission sources and hence not included in the insignificant activities list

The facility has a 40,000-gallon tank for storage of 19 percent aqueous ammonia (NH_3) for use in the SCR system. The tank will be equipped with secondary containment sized to accommodate the entire volume of one tank and sufficient freeboard for precipitation. The tanks will be located outdoors within an impermeable containment area, surrounded by a wall. The floor of the containment area will be covered with plastic balls designed to float on the liquid surface in the event of a spill, thereby reducing the exposed surface area, and minimizing potential emissions in the event of a leak or spill into the containment area. Under normal operations, the NH3 storage tanks will not be a source of emissions as it is not equipped with a breathing vent.

See discussion on 112(r) applicability in Section VII of this review.

Other storage and process tanks associated with the KMEC facility for aqueous and/or inorganic materials, which are not considered sources of emissions (as they are not equipped with vents), are summarized in Table 3-9 of the application, and reproduced below.

Table 3-9 – Project Aqueous Liquids Storage Tanks (Preliminary)

Cooling Tower			
Sodium Hypochlorite Tank	4,500	gallons	
Dispersant Tote	400	gallons	minimum 2 totes onsite at a time
H_2SO_4 Tank	6,000	gallons	
Scale/Corrosion Inhibitor Tank	2,000	gallons	
Non Oxidizing Biocide Tote	400	gallons	minimum 2 totes onsite at a time
Service Water (Includes Fire Protection Storage)	450,000	gallons	
Steam Cycle Chemical Feed			
Ammonium Hydroxide or Amines Tote	400	gallons	minimum 2 totes onsite at a time
Trisodium Phosphate Tote	400	gallons	minimum 2 totes onsite at a time
Carbohydrazide Tote	400	gallons	minimum 2 totes onsite at a time
Pretreatment of Makeup Water			
Coagulant Storage Tank (Clarifiers)	7,500	gallons	
Hypochlorite Storage Tank	4,500	gallons	
Coagulant Aid Polymer Feed Tote	400	gallons	minimum 2 totes onsite at a time
Thickener Aid Polymer Tote	400	gallons	minimum 2 totes onsite at a time
Sludge Conditioning Polymer	400	gallons	minimum 2 totes onsite at a time
Demineralizer System, RO-EDI			
RO Anti Scalant Tote	400	gallons	minimum 2 totes onsite at a time
Sodium Bisulfite Tote	400	gallons	minimum 2 totes onsite at a time
H_2SO_4 Tote	400	gallons	minimum 2 totes onsite at a time
Demineralized Water Tank	300,000	gallons	
Waste Water			
Waste Water Tank	100,000	gallons	

Applicable regulations to the insignificant activities
The following regulations are potentially applicable to these insignificant sources.

15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS
(40 CFR Part 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984)

This regulation is applicable to storage vessels with a capacity greater than or equal to 75 cubic meters (19,813 gallons) that are used to store volatile organic liquids (VOL). The storage tanks located at the KMEC facility containing VOL (i.e., I-1, -2 and -3) each have a capacity less than 19,813 gallons; therefore, Subpart Kb is not applicable.

15A NCAC 02D .0900 VOLATILE ORGANIC COMPOUNDS
15A NCAC 02D .0902 APPLICABILITY
No VOC rules apply to these sources. See discussion under Section VI.F below.

F. Facility-wide emission sources

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
The PSD regulations are designed to ensure that the air quality in current attainment areas does not significantly deteriorate beyond baseline concentration levels. PSD regulations specifically apply to the construction of EPA-defined Major Stationary Sources in areas designated as attainment or unclassified attainment for at least one of the regulated pollutants. North Carolina has incorporated EPA's PSD regulations (40 CFR 51.166) into its air pollution control regulations in 15A NCAC 02D .0530.

The construction of the entire facility was evaluated pursuant to PSD during the initial permitting process (See Section IV of this review document above). Attachment A to this review includes the complete preliminary and final determination of this initial construction project. As a result, the initial permit (Permit No. 10400R00, issued April 15, 2015) was issued with BACT limits for the following pollutants: NOx, CO, VOC, PM_{10}, $PM_{2.5}$, sulfuric acid mist (H_2SO_4) and GHGs. All emission sources listed in Section 1 of the permit were permitted with BACT emission limitations and requirements associated with these pollutants including emission limitations associated with the modeling demonstrations used to show compliance with the NAAQS and PSD increments. Since the issuance of Permit No. 10400R00, a few modifications have occurred that will be discussed below in context of the original established BACT limits and requirements.

Permit revision R01
Permit revision R01 was issued in response to an application that requested the permit be updated to reflect:
- the boiler (ID No. ES-2) constructed had a lower heat input (42 MMBtu/hr) than the one proposed in the original application (138 MMBtu/hr)
- the engine (ID No. ES-4) constructed had a lower output power rating (1,528 bhp) than the one proposed in the original application (1,850 bhp)
- a request to allow some operating allowances for the engines (ID Nos. ES-4 and ES-5) for purposes of initial commissioning.

The net result of this application resulted in a lowering of the GHG BACT limit on both engines and the incorporation of the requested operating allowance into permit revision R01. Attachment B to this review includes a full regulatory discussion for this permitting action.

<u>Permit revision R02</u>
Permit revision R02 was issued in response to an application that requested the permit be updated to clarify that PSD emission limits for the CT during startup operations (and other non-normal operations) used to show compliance with the NAAQS are based on a 3-hour average. These emission limits appear in Section 2.1 A.7.d of the draft permit. The revision was made upon the review of the original modeling analysis. Attachment C to this review includes a full regulatory discussion for this permitting action.

<u>Permit revision R03</u>
Permit revision R03 was issued in response to an application that requested removal of an ammonia emission limit that was erroneously established as a BACT limit in the initial permit (permit revision R00). Ammonia is not a regulated pollutant for PSD or TV purposes, nor is it considered a precursor for $PM_{2.5}$ under 02D .0530. This request was granted. However, the monitoring of the ammonia slip from the NOx controls (SCR system, ID No. CD-1A) on the turbine (ID No. ES-1) was retained to ensure proper operation and maintenance of the SCR system. KMEC also requested an increase in the allowable ammonia slip limit used to show proper operating and maintenance of the SCR system. Upon review of the information supplied by KMEC this request was also granted. Attachment D to this review includes a full regulatory discussion for this permitting action.

<u>Source-specific discussions</u>
Each source, or group of sources, will be discussed individually below.

Natural gas-fired combined-cycle combustion turbine with duct burner (ID No. ES-1)

The PSD requirements for this source are included in the draft air permit at Section 2.1 A.7. This source's BACT limits are best summarized by reproducing Table 2.1 A.7.a from the draft permit.

Table 2.1 A.7.a

Regulated NSR Pollutant	BACT	Control Method
PM_{10} / $PM_{2.5}$	0.0041 lb/MMBtu, CT only 0.0059 lb/MMBtu, CT and DB	Exclusive natural gas–firing
NO_x	2 ppmvd @ 15% O_2, 1 hr- basis	Exclusive natural gas firing, Dry low NOx combustors on CT,SCR on DB exhaust
CO	2 ppmvd @ 15% O_2, 1 hr- basis	*Good combustion practices (formerly combustion controls*),* oxidation catalysts
VOC	1.0ppmvd @ 15% O_2, 1 hr- basis w/o duct firing 1.5 ppmvd @ 15% O_2, 1 hr- basis with duct firing	*Good combustion practices (formerly Combustion controls*),* oxidation catalysts
H_2SO_4	0.7 grains S per 100 SCF natural gas combusted	Exclusive natural gas–firing
GHGs	gross heat rate <= 6,942 Btu/kilowatt-hr (kW-hr), HHV (gross*) at ISO** conditions, initial test gross heat rate < = 7,335 Btu/kW-hr, HHV (gross*) at ISO conditions, life of the facility	Good combustion practices; Oxidation catalysts; Low-carbon fuel; Energy efficiency/combined-cycle power plant

* See Item 1 in discussion below

** International Organization for Standardization – ISO 3977 "Gas Turbines - Procurement - Part 2: Standard Reference Conditions and Ratings"

This source is also subject to secondary BACT limits in the form of annual pollutant emission limitations on 12-month rolling total bases (draft permit Section 2.1 A.7.b) as well as emission rate limits associated with the NAAQS and PSD increment analyses (Section 2.1 A.7.d.). To assure compliance with the BACT limits and modeled emission rates, KMEC is also required to:

- limit operation during startup and shutdown operations to 500 hours per year (rolling 12-month basis);
- minimize operation during commissioning to the maximum extent possible;
- limit tuning operations to 2 events per year (rolling 12-month basis). Each event shall not exceed 8 hours; and;
- minimize emissions to the maximum extent possible during start up shutdown, commissioning and tuning operations.
- conduct initial and annual (or every five years depending on margin of compliance) tests for $PM_{2.5}$/PM_{10}, VOC and GHG (i.e., gross heat rate)
- keep fuel sulfur records
- operate NOx and CO CEMS
- calculate CO_2 (GHG) emissions consistent with 40 CFR Part 75.
- keep the associated records for the above requirements and provide semi-annual reports to the DAQ.

No substantial changes will be made to the existing BACT limitations at Sections 2.1 A.7.a, b and d. Notable changes to the existing operating restrictions, testing, monitoring recordkeeping, and reporting conditions will be discussed below. Any and all changes to the permit conditions associated with this regulation will be included in Section IX, "Changes Implemented in Revised Permit."

<u>Changes in the draft permit</u>

Item 1

As indicated with an asterisk in Table 2.1 A.7.a above, "combustion controls" are indicated as a BACT control method for CO and VOC. A review of the preliminary determination for the initial permit (revision R00), shows that the discussion of the BACT control method of "combustion controls" and "good combustion practices," to be interchangeable. To avoid the implication that these practices are active controls similar to the oxidation catalyst used post combustion, the permit will be revised to only use the term "good combustion practices." This change has no implications with any of the existing testing, monitoring, recordkeeping, or reporting requirements.

Item 2

KMEC has already met the initial testing requirements at Section 2.1 A.4.f of the existing permit (revision R03). Testing was performed between July 16 and 19, 2018 and compliance was demonstrated with each regulation evaluated for PM, PM_{10}, $PM_{2.5}$, NOx, VOC and GHGs (i.e., gross heat rate). The results were documented in the test memo issued by the Stationary Source Compliance Branch, dated December 13, 2018. This initial testing requirement will be removed from the draft permit.

Item 3
The intent of the original testing conditions at Sections 2.1 A.4.e and f were to require testing for gross heat rate for the GHG BACT limit as presented in section 2.1 A.4.a whenever a source test is required for the other pollutants. The testing language will be clarified to indicate this requirement.

Item 4
The existing permit contains the following monitoring requirements for VOC at the existing section 2.1 A.4.k.i.

> *Annual emissions of VOC shall be based upon source test data for each operating scenario, if available. If no source test data is available, the Permittee shall utilize the appropriate AP-42 emission factors, or other emission factors as approved by NC DAQ.*

Since KMEC has already conducted source testing for VOC in each operating scenario (i.e., CT operating with and without DBs) (see Item 2 above) this language will be removed from the revised permit.

Item 5
The existing permit contains the following requirement for CO_2 at Section 2.1 A.4.n.

> <u>*GHGs* - CO_2</u>
> *The Permittee shall install, certify, operate and maintain a* CO_2 *CEMS or determine its* CO_2 *emissions according to 40 CFR Part 75 Appendix G. The Permittee shall submit its monitoring plan with the Acid Rain permit application as required by condition 2.1.A.5 at least 24 months before the date on which the unit (ID No. ES-1) commences operation.* CO_2 *emissions shall be determined on an hourly basis.*

KMEC has submitted its Acid Rain Permit application (Application No. 2300383.15A). KMEC has not installed a CO_2 CEMS but is calculating its hourly CO_2 emissions via the procedures at 40 CFR Part 75, Appendix G. This condition will be simplified to reflect this CO_2 calculation methodology.

Item 6
An additional recordkeeping requirement was added to the draft permit to make the secondary BACT limits at Section 2.1 A.7.b in the draft permit practically enforceable. KMEC will simply be required to calculate emissions for the pollutants in Section 2.1 A.7.b on a monthly basis and keep them in a logbook (written or electronic).

Item 7
The existing permit contains the following language for GHGs at Section 2.1 A.4.r.

> *This reporting requirement may be revised based upon the monitoring plan submitted as required in condition n. above.*

As discussed above, KMEC is calculating its hourly CO_2 (i.e., GHG) emissions via the procedures at 40 CFR Part 75, Appendix G. This language will be removed from the draft permit.

Item 8
In Section 1 of the existing permit the oxidization catalyst is presented as a "CO oxidization catalyst." A review of the preliminary determination for the initial permit (revision R00) indicates an "oxidization catalyst" as a BACT control technology for the CO, VOC and GHGs. To reflect its purpose more correctly, the control device descriptor in Section 1 (and elsewhere as needed) will be revised to simply "oxidization catalyst" in the draft permit.

Item 9
On October 7, 2021, Jeffery Connors, a consultant on behalf of KMEC, sent an email detailing potential monitoring compliance issues with the NO_2 (as NOx) and CO limits in Section 2.1 A.7.d of the draft permit, notably, the 3-hr contiguous rolling average emission limits. Mr. Connors (and KMEC) maintains this is not an issue with compliance of the limit but rather the monitoring strategy that is implemented in the existing permit.

NOx and CO CEMs are utilized for determining compliance with these contiguous rolling 3-hour emission limits. These CEMS are required to be operated consistent with the CEMS requirements required under 40 CFR Part 60 either directly, as the NOx

CEMS is via NSPS Subpart KKKK, or as with the CO CEMS, indirectly via 15A NCAC 02D .0613. The main issue here is that the 1-hour data is based on a "one-hour period" that is defined at 40 CFR 60.2 as "any 60-minute period commencing on the hour."

40 CFR Part 60 in this situation requires data from a partial operating hour to be used to determine a full 1-hour average. Therefore, for example, if a source starts up at 10:45 into a clock hour and emits 10 pounds of a pollutant from 10:45 to 11:00, NSPS procedures would result in a 1-hour average emission rate for that clock hour of 40 pounds per hour (i.e., 10 pounds / 15 minutes) for that entire clock hour. However, only 10 pounds were actually emitted to the atmosphere in that clock hour (10 lb/hr). This calculation for a partial operating hour is the crux of the issue raised by KMEC.

In the original application's (permit revision R00) modeling demonstration, the worst-case emission rates modeled were based on vendor supplied data during a cold start of the CT. The vendor provided data to KMEC on an "event basis." Using NOx as an example, the vendor estimated that 111 pounds of NOx would be emitted over 143 minutes during a "typical cold start." For modeling purposes, this was reduced to an emission rate of 46.8 lb/hr (i.e., 111 pounds / 143 minutes) and that was very conservatively modeled for <u>every hour of the year</u>. Thus, the intent was not to create a true 1-hour emission limit of 46.8 lb/hr but rather this rate was a compromise on how to reduce the event-based data into a rate for modeling purposes.

It is worth noting here that there is an operating limit in the PSD permit condition to limit operation of the CT during startup and shutdown to 500 hours per year (not the 8760 hours per year modeled) and that the total NOx emissions <u>under all</u> operating scenarios are limited to 103.5 tpy. If the CT actually operated during startup and shutdown operations for 500 hours in one year, the emissions would be a maximum of 11.7 tpy or approximately 11% of the NOx emissions allowed in a single year (12-month rolling average). Also worth restating is that the 46.8 lb/hr NOx rate modeled for every hour of the year is equivalent to 205 tpy or approximately double the NOx emissions allowed in a year under all operating scenarios. Thus, these limitations support the slim likelihood of a NOx NAAQS exceedance. The same argument can be made for the CO emissions.

As explained in the review for permit revision R02, the 3-hour rolling average limit was introduced and applied under all scenarios. By introducing the 3-hour rolling average, it was thought that the "clock hour" approach as required under 40 CFR Part 60 could be used directly without introducing additional specific or unique monitoring or recordkeeping requirements.

However, as time progressed, KMEC has seen that using the "clock hour" approach with 40 CFR Part 60 is still potentially problematic for startup and shutdowns, the two scenarios in which partial operating hours occur. KMEC has supplied data (emails received October 7, 2021 and November 30, 2021) to show how in principle, that although the contiguous rolling 3-hour average calculated using the 1-hour averages calculated consistent with 40 CFR Part 60 can show a violation of the 3-hour rolling average emission limits in Section 2.1 A.7.d of the draft permit, a rolling 3-hour average based on the first 3 clock hours would show compliance.

It is not practical nor necessary to redefine an operating hour in general just to address this particular issue. Each time a startup was to occur, the hourly data would reflect a different sequence of clock times than those of a data set that occurred before the last shutdown or a data set that occurred after the next shutdown and subsequent startup. It is necessary to keep the operation and data collection of the CEMs consistent with the 40 CFR Part 60 requirements which ensure valid data. However, to avoid making the CEM monitoring requirements unnecessarily burdensome without any added benefit, the following language is being added to the draft permit:

vii. For purposes of complying with the NO_2 (as NO_x) and CO 3-hour contiguous rolling average limit in Section 2.1 A.7.d above, KMEC may use the following options at startups and shutdowns only:
   (A) At startup, the Permittee may use the CEM data to determine the pounds of NOx or CO emitted during the first three valid clock hours. The first 3-hour contiguous rolling average shall be calculated as the sum of the pounds of NOx or CO emitted during the first three valid clock hours divided by 3.
   (B) At shutdown, the Permittee may use the CEM data to determine the pounds of NOx or CO emitted during the last three valid clock hours. The last 3-hour contiguous rolling average shall be calculated as the sum of the pounds of NOx or CO emitted during the last three valid clock hours divided by 3.

Natural Gas-fired Auxiliary Boiler (ID No. ES-2) and Natural Gas-fired Fuel Gas Heater (ES-3)
The PSD requirements for these sources are included in the draft air permit at Section 2.1 B.5 and 6. These combustion sources are subject to BACT emission limits based on good combustion practices, use of low-NOx burners and the combustion of natural gas exclusively, as well as emission rate limits associated with the NAAQS and PSD increment analyses. To ensure compliance with the BACT limits and modeled emission rates, KMEC is also required to:

- maintain and operate the sources in a manner consistent with good air pollution control practice for minimizing emissions.
- limit boiler (ID No. ES-2) 4,000 hours of operation per year (12-month rolling total basis).
- keep fuel sulfur records

- calculate GHG emissions on a monthly a 12-month rolling basis.
- perform inspections and maintenance as recommended by the manufacturer
- keep the associated records for the above requirements and provide semi-annual reports to the DAQ.

No substantial changes will be made to the existing permit conditions. Any and all changes to the permit conditions associated with this regulation will be included in Section IX, "Changes Implemented in Revised Permit."

Emergency Generator (ID No. ES-4) and Emergency Fire Pump (ID No. ES-5)
The PSD requirements for these sources are included in the draft air permit at Section 2.1 C.4 (section 2.1 C.5 in the existing permit revision R03). These engines are subject to BACT emission limits based on good combustion practices and the combustion of low sulfur diesel fuel (15 ppm maximum sulfur content) and emission rate limits associated with the NAAQS and PSD increment analyses. They are also subject to operating restrictions during non-emergency service.

To ensure compliance with the BACT limit and modeled emission rates, KMEC is required to meet the monitoring recordkeeping and reporting requirements as required for each of these sources under its associated NSPS condition, as well as to keep records to ensure the operating limitations are being met. The permit also contains a semi-annual summary reporting requirement of the monitoring and recordkeeping activities. No substantial changes will be made to the existing permit conditions with the following exceptions:

The footnote on the BACT Limits table in Section 2.1 C.5.a of the existing permit describes that compliance with the BACT limits may be based on the use of manufacturer certifications as allowed under NSPS Subpart IIII. The BACT limits for PM, NOx, VOC and CO were based on NSPS Subpart IIII emission standards for the proposed service, engine size and model. Section 2.1 C.4.g of the draft permit requires KMEC to meet the NSPS Subpart IIII monitoring, recordkeeping, and reporting requirements for this engine, which in turn requires the purchase of a manufacturer certified engine. Therefore, the footnote will not be included in the BACT Limits table in Section 2.1 C.4.a of the draft permit as it is redundant.

The initial commissioning operating restriction for the engines found at Section 2.1 C.4.e.iii of the existing permit will be removed. Initial commissioning has already been conducted and therefore this restriction no longer applies.

Any and all changes to the permit conditions associated with this regulation for these sources will be included in Section IX, "Changes Implemented in Revised Permit."

Cooling Tower (ID No. ES-6)
The PSD requirements for this source are included in the air permit at Section 2.1 D.2. The cooling tower is a small source of $PM_{2.5}$ and PM_{10} emissions and has a BACT limit requiring the concurrent operation of the associated mist eliminator (ID No. CD-6) with a 0.0005 percent drift loss and emission rate limits associated with the NAAQS and PSD increment analyses.

To ensure compliance with the BACT limit and modeled emission rates, KMEC is required to perform manufacturer-recommended inspections and maintenance and keep the associated records. The reporting is required upon request by the DAQ. These types of monitoring, recordkeeping and reporting requirements are typical of PM sources using control devices to comply with the applicable standard (in this case 02D .0530) in NC-issued TV permits. Therefore, no substantial changes will be made to the existing permit conditions. Any and all changes to the permit conditions associated with this regulation for this source will be included in Section IX, "Changes Implemented in Revised Permit."

Fugitive Emission Sources
The existing permit contains BACT requirements for fugitive emissions of GHGs at Section 2.2 B.1 and 2. The facility includes natural gas piping to transport fuel to all combustion equipment. Natural gas piping components, such as connections, valves, compressor seals, etc. are potential small sources of fugitive methane (CH_4)and CO_2. In addition, intentional periodic purging of natural gas related to piping maintenance and turbine startups/shutdowns, as required for safety reasons, will also occur. The electrical circuit breakers at KMEC are insulated with sulfur hexafluoride (SF6) which is also regulated as a GHG and hence also a fugitive source of GHG.

Section 2.2. B.1 addresses fugitive sources of CH_4 from natural gas which as seen in Section IV above, represent a small fraction of the facility-wide GHG emissions. KMEC is required to conduct daily audio/visual/olfactory (AVO) walk-through inspections, take appropriate corrective actions if emissions are detected, and record all activities in a logbook. The Permitee is also required to submit reports upon request of the DAQ of any corrective actions taken. No substantial changes will be made to the existing permit condition with the following exception. Pursuant to the Title V reporting requirements under 15A NCAC 02Q .0508, a permit shall require semiannual reporting of required monitoring and recordkeeping activities. The daily walk-through inspections are required for monitoring purposes. Therefore, a reporting requirement for a summary of these monitoring and recordkeeping activities is being added to the draft permit.

Section 2.2. B.2 addresses fugitive sources of SF_6, which is used as an insulator in electrical circuit breakers and switches. As seen in Section IV above, these sources also represent a very small fraction of the facility wide GHG emissions. KMEC is required to use enclosed circuit breakers with leak detection, low pressure alarms and low-pressure lockout mechanisms. KMEC is also required to calculate the monthly SF6 emissions using specific procedures in 40 CFR Part 98 Subpart DD. KMEC is also required to submit semiannual reports of these monitoring and recordkeeping activities list. No substantial changes will be made to the existing permit condition with the following exception. To be consistent with current TV permitting policy and for practical enforceability, in addition to the monthly calculation of SF6 emissions, the requirement to keep such calculations in a logbook will be added to the draft permit. It will also be clarified to keep such records on an SF6 on a CO_2 equivalent basis to align with the existing reporting requirement.

Any and all changes to the permit conditions associated with this regulation for these sources will be included in Section IX, "Changes Implemented in Revised Permit."

15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING [40 CFR Part 64]

Compliance assurance monitoring (CAM) is intended to provide a reasonable assurance of compliance with applicable requirements under the Clean Air Act (CAA) for large emission units that rely on pollution control device equipment to achieve compliance. The CAM rule at 40 CFR Part 64 is implemented via the state rule 15A NCAC 02D .0614.

02D .0614(a) states:

> (a) General Applicability. Except as set forth in Paragraph (b) of this Rule, the requirements of this Paragraph shall apply to a pollutant-specific emissions unit at a facility required to obtain a permit pursuant to 15A NCAC 02Q .0500 if the unit:
> (1) is subject to an emission limitation or standard for the applicable regulated air pollutant, or a surrogate thereof, other than an emission limitation or standard that is exempt pursuant to Subparagraph (b)(1) of this Rule;
> (2) uses a control device to achieve compliance with any such emission limitation or standard; and
> (3) has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this Subparagraph, "potential pre-control device emissions" means the same as "potential to emit" as defined in 15A NCAC 02Q .0103, except that emission reductions achieved by the applicable control device shall not be taken into account.

02D .0614(b) includes exemptions to the rule. These will be discussed as necessary below.

Note that a pollutant-specific emissions unit (PSEU) is defined in at 40 CFR 64.1 as an emissions unit considered separately with respect to each regulated air pollutant. Also note that TAPs are not considered regulated air pollutants as defined at 40 CFR 64.1 and hence not subject to CAM.

Applicability will be addressed for all on-site sources below.

<u>One natural gas-fired combined-cycle combustion turbine (CT) (ID No. ES -1)</u>
This source has "potential pre control device emissions" exceeding "100 percent of the amount, in tons per year, required for a source to be classified as a major source" (i.e., under Title V) for NOx, CO, VOC and GHGs. For these pollutants, this threshold is 100 tpy. Each pollutant will be addressed separately.

GHGs
The GHG emissions are regulated under NSPS Subpart TTTT (15A NCAC 02D 0524) and under PSD (15A NCAC 02D .0530).

NSPS Subpart TTTT is an "emission limitation(s) or standard(s) proposed by the Administrator of the Environmental Protection Agency after November 15, 1990, pursuant to section 111 or 112 of the federal Clean Air Act. A control device is not used to is not used achieve compliance with this standard. As such, this source does not meet the CAM applicability requirements for this rule pursuant to 15A NCAC 02D .0614(a)(2).

With respect to PSD, the primary BACT limit (emission limitation) is specified in terms of gross heat rate (Btu/kW-hr) and specifies the BACT technology to include the use of the oxidation catalyst. This specification was mainly the result of the fact that the catalyst was necessary for NOx and CO reductions but would have secondary reductions for the relatively small amount of methane (CH4) emissions which is a GHG pollutant. The derivation of the "emission limit" in terms of gross heat rate does not include the effect of any oxidation of CH_4. The secondary BACT limit is specified in terms of tons per year. However, the derivation of this limit also did not include the effect of any oxidation of CH_4. A review of the derivation of GHG emissions show that the methane emissions from the combustion turbine represent less than 0.2% of the GHG emissions from the turbine on a CO_2 equivalent (CO_2e) basis. Thus, with respect to PSD, a control device is not relied upon to achieve compliance. Therefore, the CT does not meet the CAM applicability requirements for this rule pursuant to 15A NCAC 02D .0614(a)(2).

NOx

The NOx emissions are regulated under NSPS Subpart KKKK (15A NCAC 02D 0524) and under PSD (15A NCAC 02D .0530). NSPS Subpart KKKK is an "emission limitation(s) or standard(s) proposed by the Administrator of the Environmental Protection Agency after November 15, 1990, pursuant to section 111 or 112 of the federal Clean Air Act. As such this source is exempt from CAM requirements for this rule pursuant to 15A NCAC 02D .0614(b)(1)(A).

02D .0614 (b)(1)(A) states:

> (b) The following exemptions to this Rule shall apply.
> (1) Exempt emission limitations or standards. The requirements of this Rule shall not apply to any of the following emission limitations or standards:
> (A) emission limitations or standards proposed by the Administrator of the Environmental Protection Agency after November 15, 1990, pursuant to section 111 or 112 of the federal Clean Air Act;

For PSD, NOx CEMS is used to determine compliance. The use of the CEMS meets the definition of a "continuous compliance method" pursuant to 40 CFR 64.1. As such this source is exempt from CAM requirements for this rule pursuant to 15A NCAC 02D .0614(b)(1)(F).

02D .0614(b)(1)(F) states:

> (b) The following exemptions to this Rule shall apply.
> (1) Exempt emission limitations or standards. The requirements of this Rule shall not apply to any of the following emission limitations or standards:
>
> ***
>
> (F) emission limitations or standards for which a permit issued pursuant to 15A NCAC 02Q .0500 specifies a continuous compliance determination method, as defined in 40 CFR 64.1.

CO

The CO emissions are regulated only under PSD (15A NCAC 02D .0530). For PSD, CO CEMS is used to determine compliance. The use of the CEMS meets the definition of a "continuous compliance method" pursuant to 40 CFR 64.1. As such this source is exempt from CAM requirements for this rule pursuant to 15A NCAC 02D .0614(b)(1)(F).

VOC

The VOC emissions are regulated only under PSD (15A NCAC 02D .0530). Under PSD, a control device, the oxidization catalyst, is used to achieve compliance. However, although the "potential pre control device emissions" are over 100 tpy, its potential to emit (PTE), as defined at 40 CFR 64.1, which includes "any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment" is less than 100 tpy (i.e., 86.9 tpy, see section IV above). As such, this source is considered an "other pollutant specific emission unit" as defined at 40 CFR 64.5 and therefore is not required to submit a CAM plan until the first renewal of the Title V permit.

<u>Multi-cell cooling tower (ID No. ES-6) controlled by a mist eliminator (ID No. CD-6)</u>

Although this source utilizes a control device to comply with the PM emission limitations under PSD (15A NCAC 02D .0530), its "potential pre control device emissions" are less than 100 tpy of PM. As such, this source does not meet the CAM applicability requirements for this rule pursuant to 15A NCAC 02D .0614(a)(3).

<u>All other sources</u>

No other sources at the facility use a control device to achieve compliance with a standard. As such, these sources do not meet the CAM applicability requirements for pursuant to 15A NCAC 02D .0614(a)(2).

<u>State Enforceable Only</u>
15A NCAC 02Q .0700: TOXIC AIR POLLUTANT PROCEDURES
15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS

The regulations at 15A NCAC 02Q .0700 require, with some exceptions, a permit to emit any toxic air pollutant (TAP) at levels greater than the TAP permitted emission rate (TPER) specified in 15A NCAC 02D .0711. These regulations include the procedural rules used to comply with the TAP control requirements found at 15A NCAC 02D .1100. 15A NCAC 02D .1104 contains Acceptable Ambient Levels (AALs) for each TAP. Generally, a facility must conduct a dispersion modeling analysis to demonstrate that each TAP emitted above its respective TPER will not result in the respective AAL being exceeded beyond the facility's premises. Collectively, these "toxics" rules are state-enforceable only and are not subject to the TV requirements found at 15A NCAC 02Q .0500.

The TAP emissions from this facility were evaluated during the initial permitting process (See Section IV of this review document). Attachment A to this review includes the complete preliminary and final determination of this initial construction project. The six TAPS identified to be emitted at levels greater than their respective TPER were formaldehyde, sulfuric acid mist (H_2SO_4), ammonia, arsenic, benzene and cadmium.

The formaldehyde, sulfuric acid mist (H_2SO_4) and ammonia emissions were included in a dispersion modeling analysis that was approved by the DAQs Air Quality and Analysis Branch (AQAB) in a memo dated February 13, 2015, and the arsenic, benzene and cadmium emissions were included in a dispersion modeling analysis that was approved by the AQAB in a memo dated February 24, 2015.

The combined results of the analyses are summarized in the table below.

Pollutant	Averaging Period	Max Facility Impact ($\mu g/m^3$)	AAL ($\mu g/m^3$)	Percent of AAL
H_2SO_4	1-hour	5.84	100	6 %
	24-hr	3.5	12	29 %
Ammonia	1-hour	27.41	2,700	1 %
Formaldehyde	1-hour	0.77	150	<1 %
Arsenic	Annual	6.1e-06	0.0021	<1 %
Benzene	24-hr	4.6e-04	0.12	<1 %
Cadmium	24-hr	2.7e-05	0.0055	<1 %

The maximum facility impacts shown in the table above were based on maximum potential hourly emission rates. Comparing these values to the respective AALs shows the margin of compliance with each of the AALs is large. To minimize any permit compliance issues but still maintain a large margin of compliance with the AALs, the allowable emission rates incorporated into the permit were, with the exception of ammonia and H_2SO_4 for the combustion turbine, double the modeled emission rate. As a result, the initial permit (Permit No. 10400R00, issued April 15, 2015) was issued with the following TAP allowable emission rates at Section 2.2 A.1:

Emission Source	**Allowable Emission Rates**					
	Arsenic	Benzene	Cadmium	Formaldehyde	Sulfuric Acid	Ammonia
ID No. ES-1: Natural gas-fired combined-cycle combustion turbine with duct burner	12 lb/yr	630 lb/yr	61 lb/yr	1.17 lb/hr	5.52 lb/hr	25.9 lb/hr (2400 lb/hr)*
ID No. ES-2: Natural Gas-fired Auxiliary Boiler	0.22 lb/yr	2.28 lb/yr	1.18 lb/yr	0.02 lb/hr	0.06 lb/hr	NA
ID No. ES-3: Natural Gas-fired Fuel Gas Heater	0.03 lb/yr	0.32 lb/yr	0.17 lb/yr	0.003 lb/hr	0.004 lb/hr	NA

* Revised ammonia limit in permit revision R03

In a subsequent permitting action, permit revision R03 (See Section IV) was issued in response to an application that requested removal of an ammonia emission limit that was erroneously established as a BACT limit in the initial permit (permit revision R00) in the 15A NCAC 02D .0530 condition found at Section 2.1 A.5. KMEC also requested an increase (double) in the allowable ammonia slip limit (5 ppm to 10 ppm) used to show proper operating and maintenance of the SCR system and also requested an increase in the allowable ammonia emission limits under the 02D .1100 condition found at Section 2.1 A.1. As seen in the table above, the margin of compliance of the permitted allowable emission rate for ammonia of 25.9 lb/hr with respect to the AAL was large (the maximum impact was approximately 1% of the AAL, see table above). To minimize, or rather remove any doubt, that an exceedance of the revised ammonia slip limit of 10 ppm (or approximately 52 lb/hr) in the revised PSD condition found at Section 2.1 A.5 would also result in an inadvertent violation of the allowable ammonia emission limit at Section 2.2 A.1, KMEC requested the allowable emission rate be scaled to correspond to an ambient impact of 95% of the AAL. For a single source of emissions, the modeled impact is directly proportional to the emission rate. The corresponding emission rate of ammonia that would result in an ambient impact of 95% of the AAL is approximately 2400 lb/hr. Thus, KMEC would have to exceed the revised ammonia slip monitoring limit under 02D .0530 by a factor of approximately 46 (i.e., 2400/52) before the ammonia emissions would be expected to result in an ambient impact approaching the ammonia AAL. This is typical practice under the 02D .1100 rules to simplify monitoring requirements for sources with large margins of compliance with a given AAL. The allowable emission rate was therefore revised to 2400 lb/hr. Attachment D to this review includes a full regulatory discussion for this permitting action.

The existing permit condition also contains the following restriction:

> To comply with the TAP emissions limitations in Section 2.2 A.1.a. above, the Permittee may only fire natural gas in the combustion turbine and duct burner (ID No. ES-1), the auxiliary boiler (ID No. ES-2) and the gas heater (ID No. ES-3).

Note that these sources are only permitted to burn natural gas. A permit modification would be necessary to fire different fuels and hence require a revised regulatory review. Thus, thus operating restriction in the exiting permit is redundant and unnecessary. This unnecessary operating restriction will be removed.

The existing permit requires no monitoring, recordkeeping or reporting since these emission limitations are based on potential emission estimates with large margins of compliance with each TAPs respective AAL. No changes will be made to the revised permit with respect to the monitoring, recordkeeping and reporting.

Consistent with current permitting policy, language will be added to the permit that memorializes when the dispersion modeling analyses were submitted and approved by the AQAB as well as the following requirement:

> Placement of the emission sources, configuration of the emission points, and operation of the sources shall be in accordance with the submitted dispersion modeling analysis and should reflect any changes from the original analysis submittal as outlined in the AQAB review memo.

Also note that the existing 02D .1100 permit condition does not contain allowable emission rates for the emergency generator (ID No. ES-4) or the fire pump engine (ID No. ES-5). Both of these sources are subject to MACT ZZZZ as discussed in Section VI.C of this review. As such, they meet the toxics permitting exemption at 15A NCAC 02Q .0702(a)(27). Pursuant to 15A NCAC 02Q .0706(c), these sources are to be evaluated to determine that there is no unacceptable risk pursuant to G.S. 143-215.107(a)(5)(b). This statute requires that a source meeting the exemption at 15A NCAC 02Q .0702(a)(27) shall be exempt from toxics permitting (and hence no permit TAP emissions limitations) only if it poses no unacceptable risk to human health. This evaluation does not necessarily need to be based on a dispersion model. In this particular case, these sources were included in the dispersion model for arsenic, benzene and cadmium emissions that was approved by the AQAB in a memo dated February 24, 2015. Thus, with respect to these pollutants it is clear there is no unacceptable risk. With respect to the formaldehyde, sulfuric acid mist, and ammonia model approved on February 13, 2015, the engines represent a very small fraction of the facility-wide emissions for each of these pollutants. The two engines represent less than 0.1% of the facility-wide emissions of formaldehyde and even less for sulfuric acid mist and ammonia. Given that the potential emissions of these engines were represented in the dispersion analyses, the large margin of compliance with respect to each of the TAP's AAL in those analyses, and the small contributions from these engines to the facility-wide emissions of the TAPs, it's reasonable to conclude that exempting these engines from toxics permitting pursuant to 15A NCAC 02Q .0702(a)(27) will not pose an unacceptable risk to human health.

15A NCAC 02D .0900 VOLATILE ORGANIC COMPOUNDS (VOCs)
15A NCAC 02D .0902 APPLICABILITY

15A NCAC 02D .0902(e) lists VOC standards that apply statewide. However, none of these standards apply to any of the sources or activities at the subject facility. Furthermore, the facility is located in Cleveland County. Cleveland County is considered in attainment and is not a maintenance area for the 1997 8-hour NAAQS for ozone. As such, 02D .0900 VOC standards are not applicable to this facility pursuant to 02D .0902(g).

VII. NSPS, NESHAPS, PSD, Attainment Status, 112(r), and CAM

NSPS

The gas turbine (ID No. ES-1) is subject to:

- 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.
- 40 CFR Part 60, Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

See Section VI for a full discussion.

One boiler (ID Nos. ES-2) is subject to:

- 40 CFR Part 60, Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units."

See Section VI for a full discussion.

The two engines (ID Nos. ES-4 and ES-5) are subject to

- 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."

See Section VI for a full discussion.

No other NSPS apply at the facility.

NESHAP/MACT

The facility is an area (non-major) source of HAP as its facility-wide potential emissions are less than 10 tons per year of each HAP and less than 25 tpy of all HAPs. The following MACTs are potentially applicable to the combustion turbine (ID No.ES-1).

- Subpart DDDDD - NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
- Subpart YYYY (NESHAP for Stationary Combustion Turbines)

These MACTs are only applicable at major sources of HAPs. Thus, these rules do not apply.

- Subpart JJJJJJ (NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources)
  This area source MACT is potentially applicable to the HRSG component of ID No. ES-1. The HRSG is defined as a waste heat boiler under the rule (even with the added heat from the duct burner), which is also excluded from the definition of a boiler. Therefore, this rule is not applicable to the HRSG.

Thus, no NESHAP or MACT apply to the gas turbine (ID No. ES-1).

The two boilers (ID Nos. ES-2 and ES-3) are not subject to either

- 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; or
- 40 CFR 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

See Section VI for a full discussion.

The two engines (ID Nos. ES-4 and ES-5) are subject to the area source requirements of

- 40 CFR 63, Subpart ZZZZ, "National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

See Section VI for a full discussion.

No other MACT or any NESHAPS rules apply to this facility.

PSD

This facility is located in Cleveland County. The attainment status for each criteria pollutant is either unclassifiable or in attainment, hence Non-Attainment New Source Review Regulations do not apply. The facility is a PSD major source and is subject to numerous PSD requirements. See Section VI.F for a full discussion.

CAM

CAM applicability is addressed in Section VI.F of this review.

112r - Risk Management Program (RMP) (15A NCAC 2D .2100)

EPA's Risk Management Plan Rule (RMP), codified in 40 CFR Part 68, requires that facilities with large quantities of highly hazardous chemicals prepare and implement a program to prevent the accidental release of those chemicals. KMEC is uses a dilute (19 percent by weight) solution of aqueous ammonia for the SCR NOx control system in lieu of anhydrous or higher concentration aqueous ammonia solutions, which are regulated under RMP if used or stored in amounts greater than 10,000 pounds (anhydrous ammonia) or 20,000 pounds (aqueous ammonia in concentrations of 20 percent or greater).Therefore, the RMP regulations are not applicable.

VIII. Compliance History

The most recent compliance inspection report by Melinda Wolanin of the Mooresville Regional Office (February 8, 2022) states the following:

> Based on my observations during this inspection via Microsoft Teams, this facility appeared to be in compliance with the applicable air quality regulations.

No other compliance issues were noted in the report.

IX. Changes Implemented in Revised Permit

See permit attachment. Will add here once review is complete.

X. Public Notice/EPA and Affected State(s) Review

A notice of the DRAFT initial Title V Permit, including the initial Title IV acid rain permit, shall be made pursuant to 15A NCAC 02Q .0521. The notice will provide for a 30-day comment period, with an opportunity for a public hearing. Consistent with 15 A NCAC 02Q .0525, the EPA will have a concurrent 45-day review period. Copies of the public notice shall be sent to persons on the Title V mailing list and EPA. Pursuant to 15A NCAC 02Q .0522, a copy of each permit application, each proposed permit, and each final permit pursuant shall be provided to EPA.

Also pursuant to 02Q .0522, a notice of the DRAFT Title V Permit shall be provided to each affected State and local program at or before the time notice provided to the public under 02Q .0521 above. Current NC permitting policy is to provide notice to all local programs in NC and all contiguous states regardless of their status as an affected state under 02Q .0522.

~~*Notice of the DRAFT Title V Permit to Affected States ran from XXXX YY, 2020, to XXXX YY, 2020.* ***Update with comments received from Affected States.***~~

~~*Public Notice of the DRAFT Title V Permit ran from XXXX YY, 2020, to XXXX YY, 2020 on the DAQ website and in the newspaper "X"X"X"* ***Update with public comments received.***~~

~~*EPA's 45-day review period ran concurrent with the 30-day Public Notice, from XXXX YY, 2020, to XXXX YY, 2020.* ***Update with comments received from EPA and U.S. EPA Region 4 regarding the DRAFT Title V Permit.***~~

XI. PE Seal

Pursuant to 15A NCAC 02Q .0112 "Application requiring a Professional Engineering Seal," a professional engineer's seal (PE Seal) is required to seal technical portions of air permit applications for new sources and modifications of existing sources as defined in 15A NCAC 02Q .0103 that involve:

(1) design;
(2) determination of applicability and appropriateness; or
(3) determination and interpretation of performance; of air pollution capture and control systems.

A professional engineer's seal (PE Seal) **was not** required for this initial TV permitting action (Application No. 2300383.19A) or Title IV acid rain permitting action (Application No. 2300383.15A) since it did not involve a new source or a modification to existing sources.

XII. Zoning

A zoning consistency determination per 02Q .0304(b) was **NOT** required for this permitting action as it is not a new facility or the expansion of an existing facility.

XIII. Recommendations

TBD based on public/EPA comment received, if any.
~~*This permit application has been reviewed by NC DAQ to determine compliance with all procedures and requirements. NC DAQ has determined that this facility appears to be complying with all applicable requirements.*~~

~~*Recommend Issuance of Permit No.*~~ 10400T04

Attachment A

Preliminary and Final Determination for No. 10400R00 (Application No. 2300383.14A)

NORTH CAROLINA DIVISION OF AIR QUALITY

PSD Final Determination

Permit Issue Date: **APRIL 15, 2015**

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300383
Inspector's Name:
Date of Last Inspection:
Compliance Code:

Facility Data

Applicant (Facility's Name): Kings Mountain Energy Center

Facility Address:
Kings Mountain Energy Center
180 Gage Road
Kings Mountain, NC 28086

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

Facility Classification: Before: <BFacClass> **After:** <AFacClass>
Fee Classification: Before: <BFeeClass> **After:** <AFeeClass>

Permit Applicability (this application only)
See preliminary determination

SIP:
NSPS:
NESHAP:
PSD:
PSD Avoidance:
NC Toxics:
112(r):
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Michael Green Vice President (904) 687-1857 24 Cathedral Place St. Augustine, FL 32084	Michael Green Vice President (904) 687-1857 24 Cathedral Place St. Augustine, FL 32084	Michael Holzman Senior Advisor (860) 523-8345 57 Mountain View Drive West Hartford, CT 06117

Application Data

Application Number: 2300383.14A
Date Received: 08/01/2014
Application Type: Greenfield Facility
Application Schedule: PSD

Existing Permit Data

Existing Permit Number: NA
Existing Permit Issue Date: NA
Existing Permit Expiration Date: NA

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP

Greenfield No actual emissions to date

Review Engineer: Joseph Voelker

Review Engineer's Signature: **Date:** 4/15/15

Comments / Recommendations:
Issue 10400R00
Permit Issue Date: April 15, 2015
Permit Expiration Date: March 31, 2023

1. Introduction

NTE Carolinas, LLC (NTE) is proposing to construct and operate a natural gas-fired combined-cycle power plant to be known as the Kings Mountain Energy Center (KMEC or Project). The Project will be located near the City of Kings Mountain in Cleveland County, North Carolina (Project Site). The project is fully described in the "Preliminary Determination" which is included as an attachment.

Under the North Carolina Division of Air Quality (NCDAQ)'s Title V Operating Permit regulations (15A NCAC 02Q .0500), a Title V permit is required for Major Stationary Sources. Based on the estimated potential emissions from the Project as presented in Section 3, Table 3-11of the application, the Project will be a Major Stationary Source subject to Title V permitting. During the initial permitting process however, the Permittee has opted for the application to be processed pursuant to 15A NCAC 2Q .0501(c)(2) and 2Q .0504, which allows for the application to be processed under the State permitting rules

(2Q .0300) and the PSD rule (15A NCAC 2D .0530). The Permittee will then have one year from the date of beginning operation of the facility or source to file an application following the Title V permitting procedures.

This final determination document will address and complete the applicable requirements under the following regulations:

- 15A NCAC 2Q .0306 “Permits Requiring Public Participation,”
- 15A NCAC 2Q .0307 “Public Participation Procedures,”
- 15A NCAC 2Q .0308 “Final Action on Permit Applications”
- 15A NCAC 2D .0530 “Prevention of Significant Deterioration”
- 15A NCAC 2D .0544 “Prevention of Significant Deterioration Requirements for Greenhouse Gases”

To this end, the NCDAQ:

- On May 27, 2014, the Federal Land Managers for all Class 1 areas within the vicinity of the NTE project including the National Parks Service, Forest Service, and Fish and Wildlife Service were contacted and notified of the proposed project and were also provided a copy of the PSD Pre-Application Checklist. The FLMs responded on that same date stating that no analysis would be required on their part.

- On February 27, 2015, published a “Public Notice on Preliminary Determination Regarding Approval of an Application Submitted Under the Regulations for the Prevention of Deterioration of Air Quality” in the Shelby Star newspaper.

- On February 27, 2015, sent an electronic copy of the preliminary determination, draft permit, and public notice to:
  - the applicant.
  - the USEPA Region IV
  - the Cleveland County Manager
  - the NCDAQ Mooresville Regional Office.
  - all affected states
  - all interested parties as defined at 2Q .0307(b) and (h)

- On February 27, 2015, sent a hard copy of the public notice to the Cleveland County Manager.

- On March 17, 2015, re-published a “Public Notice on Preliminary Determination Regarding Approval of an Application Submitted Under the Regulations for the Prevention of Deterioration of Air Quality” in the Shelby Star newspaper. The USEPA had requested additional time for review. As a result, the NCDAQ extended the public notice comment period for the general public as well.

- On April 15, 2015, the 30 day public comment period ended. The only comments received were from USEPA region IV.

2. Comments on the Draft Permit and Preliminary Determination

As stated in section 1. above, the only comments received were from the USEPA, Region IV, in a letter dated April14, 2015. Given the number of comments, the comments are reproduced verbatim in an attachment. The NCDAQs responses are indicated in BOLD.

3. DAQ Recommendations

The NCDAQ recommends issuing the FINAL air permit for the proposed project as described in the preliminary determination, with the changes indicated in the NCDAQs responses to the USEPA comments.

ATTACHMENT A

EPA REGION IV COMMENTS RECEIVED
APRIL 14, 2015
AND ASSOCIATED NCDAQ RESPONSES

NC DAQ's Response to the Comments provided by the USEPA on April 14, 2015.

All EPA comments were reproduced verbatim from the letter submitted received on April 14, 2015. NCDAQ's comments are indicated in Bold.

1. PM2.5 Increment Analysis:

According to page 59 of the Air Permit Review document, North Carolina based its Class II increment analysis on a $PM_{2.5}$ major source baseline date of January 6, 1975. The air permit application dated July 2014 indicates use by the applicant of an October 20, 2010 major source baseline date. It is our understanding that the applicant prepared a revised $PM_{2.5}$ PSD increment analysis utilizing January 6, 1975, as the major source baseline date at North Carolina Department of Environment and Natural Resources (NC DENR)'s request. The U.S. Environmental Protection Agency disagrees with NC DENR's use of the 1975 baseline date, which is the previously established major source baseline date for PM_{10} increment assessment. The major source baseline date for $PM_{2.5}$ PSD increment assessment established in federal PSD regulations is October 20, 2010. As such, to comply with Clean Air Act section 165(a)(3), the owner or operator of a new or modified major stationary source must demonstrate that emissions from construction or operation of such source will not cause or contribute to air pollution in excess of the available $PM_{2.5}$ PSD increment based on an analysis that utilizes the federally applicable October 20, 2010 major source baseline date.

With respect to the Kings Mountain Energy Center PSD permit application, NC DENR provided the EPA with both the applicant's original $PM_{2.5}$ PSD increment analysis utilizing the federally applicable October 20, 2010 major source baseline date and the analysis prepared by the applicant upon NC DENR's request utilizing a January 6, 1975 major source baseline date. *For purposes of complying with Clean Air Act section 165(a)(3), the applicant must ensure that compliance with the* $PM_{2.5}$ *PSD increment is established through an analysis that utilizes the federally applicable October 20, 2010 major source baseline date.* In the comments below, the EPA identifies issues regarding both of the submitted analyses. Although the NC DENR PSD Preliminary Determination used the analysis associated with the January 6, 1975 major source baseline date, for federal law purposes, it is the analysis utilizing the applicable October 20, 2010 baseline that serves to demonstrate compliance with the $PM_{2.5}$ PSD increment.

DAQ Response

The Permittee has supplied two independent PM2.5 PSD increment analyses; the initial analysis was based on the current federally applicable October 20, 2010 major source baseline date. The second analysis was based on January 6, 1975 major source baseline date. Both analyses were reviewed by the DAQ and show, under either baseline date scenario that the NTE project does not contribute significantly to any exceedances of the PM2.5 Class II Area increment.

The following comments are associated with the Applicant's 24-hour PM2.5 PSD increment compliance modeling (using the 2010 major baseline date).

a. The proposed project is the first PSD permit in the air quality control region after the $PM_{2.5}$ major source baseline and trigger date. It therefore sets the minor source baseline date for this pollutant in this air quality control region. This would be the only PSD affecting source for modeled receptors within the air quality control region.

DAQ response

NCDAQ has confirmed that the Minor Source baseline date (MnSBD) has not yet been triggered in the surrounding counties.

b. The modeled receptor grid(s) cover a large area. The minor source baseline date(s) of concern is receptor dependent. Confirmation is needed that this PSD permit application sets the earliest $PM_{2.5}$ minor source baseline date for all air quality control regions with modeled receptors. If not, more than one minor source baseline date should have been considered in defining the inventory of $PM_{2.5}$ PSD increment affecting emission units for PSD increment compliance assessment.

DAQ response

This comment is correct.

The following comments are associated with the revised modeling (1975 major source baseline date).

a. The EPA major source baseline date was appropriately used for the $PM_{2.5}$ PSD increment compliance assessment in the initial application. This revised $PM_{2.5}$ PSD increment assessment should not considered in the final permit review.

DAQ response
The Permittee has supplied two independent PM2.5 PSD increment analyses; the initial analysis was based on the current federally applicable October 20, 2010 major source baseline date. The second analysis was based on January 6, 1975 major source baseline date. Both analyses were reviewed by the DAQ and show, under either baseline date scenario that the NTE project does not contribute significantly to any exceedances of the PM2.5 Class II Area increment.

b. The 1975 major source baseline date inventory of $PM_{2.5}$ increment affecting emission units/source was not developed. The difficult task of constructing an inventory of PSD affecting emission unit/sources from historic records was not performed. Instead, the revised increment assessment modeling used the complete NAAQS inventory of other $PM_{2.5}$ emission units/sources. That is, this assessment conservatively assumed all emission units/sources in the NAAQS compliance inventory also consumed PSD increment.

DAQ response
This comment is correct.

c. Only the highest second-high (H2H) $PM_{2.5}$ modeled concentration was provided and discussed. This concentration exceeded the PSD increment for each modeled operating scenario. The H2H concentrations were about three times greater than the PSD increment but the project's contribution to the concentrations were not significant. As noted in our comments below for the NAAQS assessments, the project's contribution to all modeled concentrations greater than the PSD increments and/or NAAQS needs to be assessed. Confirmation is needed that all modeled $PM_{2.5}$ modeled increment exceedances were evaluated and the project's contribution to each modeled exceedance was less the significant impact level.

DAQ response
All modeled increment exceedances were evaluated and the project's contribution to each modeled exceedance was less than the significant impact level. Refer also to the response to Item 4.a.i. below.

d. Because the $PM_{2.5}$ PSD increment compliance modeling appears to have used the same project emissions and NAAQS emission inventory, the differences between the maximum reported concentrations for the same receptor should be based only on the form of the ambient standard (i.e., For NAAQS compliance the 8^{th} highest in 5-years and highest second-high value for PSD increment). The same receptor reported 8^{th} highest $PM_{2.5}$ modeled NAAQS concentration is more than twice that reported for $PM_{2.5}$ increment compliance (i.e., 71.9 $\mu g/m^3$ verses 30.3 $\mu g/m^3$). The difference in these reported concentrations should be explained.

DAQ response
The supplementary PM2.5 increment analysis applying the 1975 baseline date was conducted in response to NC DAQ's request several months after the NAAQS analysis. The applicant made further adjustments to the Agency-provided inventories for the PM2.5 increment analysis that were not reflected in the previously-conducted NAAQS analysis. For example, the PM2.5 emissions for a modeled, off-site granite quarry (Martin Marietta) were assumed to be equal to uncontrolled PM10 emission rates in the NAAQS model. For the supplemental increment analysis, the PM2.5 emissions were assumed to be equal to controlled PM10 emission rates based on permit requirements for the use of wet suppression. NC DAQ determined that this was a reasonable adjustment. Indeed, the estimated PM2.5 emission rate used in the increment model is believed to be conservatively high on the basis that fine particulate (PM2.5) is only a fraction of PM10 emission expected to result from stone crushing, handling and storage operations at granite quarries.

e. As indicated for the NAAQS compliance modeling, all modeled controlling concentrations or concentrations exceeding applicable ambient standards, and concentrations challenging the these concentrations (e.g., within 10%), should be modeled to 100-m resolution. Confirmation is needed that appropriate 100-m resolution receptor grids were used in the 24-hour and annual PM2s PSD increment compliance modeling.

DAQ response
It has been confirmed, through review of model output files and graphics, that all max. impact/controlling concentrations were located in areas with 100 meter receptor grid resolution.

2. **Draft Permit Conditions:**

a. According to Table 4b on page 6 of the draft permit, the combustion turbine (ES-1) is subject to secondary best available control technology (BACT) limitations for all pollutants subject to PSD on a ton per year (TPY) basis that includes startup/shutdown/commissioning, tuning, and normal operations. Please clarify in the final permit that all of these secondary BACT limits apply on a 12-month rolling basis.

<u>DAQ response</u>
The permit was revised to clarify that the limits in Table 4b on page 6 of the draft are on a 12-month rolling basis.

b. In addition to the TPY emission limits in Table 4b, the permit should also contain either a short-term emission limit (*e.g.*, lb/hr) during startup/shutdown events or a limit on the duration of (minutes) and emissions during (lbs) startup/shutdown events. According to the Revised Start-Up Modeling Analysis report dated February 11, 2015, the value of 5.89 grams/second was modeled as the worst-case emissions during startup/shutdown events. This value corresponds to the worst-case scenario of a cold startup event lasting 143 minutes emitting 111 lbs of NO_2 per event, according to Table 5-6 of the application. Consequently, since this value was used in the modeling analysis to ensure the 1-hr NO_2 NAAQS would be met during all startup/shutdown scenarios, the final permit should contain permit condition(s) as suggested above to ensure the NO_2 NAAQS modeling analysis remains appropriate.

<u>DAQ response</u>
Condition 2.1.4.d of the draft permit contains two short term emission limitations for NO2, 28.4 lb/hr during 50 to 100% full load and 46.8 lb/hr during all other operating scenarios. "All other operating scenarios" includes start-up and shut down events. 46.8 lb/hr is equivalent to 5.89 grams/second, the emission rate modeled as the worst-case emissions during startup/shutdown events as described above. The permit will be revised to clarify that "all other operating scenarios" includes all start-up and shutdown events.

c. According to the modeling analysis, the emergency diesel generator and fire-water pump were indicated to operate for testing at most once per week for less than 30 minutes at a time and will not be operated simultaneously during testing. The permit already seems to contain operating restrictions that limit non-emergency operations of each of these diesel engines to 50 hour per year (as part of the NSPS). However, in order to exclude these diesel generations from the impact modeling, the permit also must include a limit of 30 minutes per event and an exclusion from operating simultaneously during testing.

<u>DAQ response</u>
The permit was revised include a limit of 30 minutes per hour of non-emergency operation and an exclusion from operating simultaneously during testing.

d. According to the emission calculations in the application, the preliminary determination (page 10) and the modeling analysis, the auxiliary boiler will only operate 4,000 hours per year. In order for the emission estimates, applicability, and modeling analyses to remain valid, the permit must include a 4,000 hour per year limit on the operation (on a 12-month rolling basis) of the auxiliary boiler.

<u>DAQ response</u>
The permit was revised to include a 4,000 hour per year limit on the operation (on a 12-month rolling basis) of the auxiliary boiler.

3. Air Permit Review (preliminary determination) document:

a. According to page 57 of the Air Permit Review document, a netting analysis was performed and the heading of Table 1 refers to Pollutant Netting Analysis. Since this is a greenfield (new) source, a netting analysis was not performed and is not applicable to a new source. Please clarify this in the final determination.

DAQ response
That is correct, a true "netting analysis" was not performed nor is applicable in this case.

b. Table 3 & 4 (page 59) mention Maximum onsite and offsite source impacts. This is misleading since the values lists are not the maximum values but those associated with the form of the NAAQS. For example, the NO_2 value, it is the 8th highest value (consistent with the NAAQS) and not the "maximum" value. Please clarify this in the final determination.

DAQ response
EPA's comment is correct.

c. Table 3 lists the Class II area NAAQS Modeling Results, however, the value listed for NO_2 is 171.79 $\mu g/m^3$. This value is from the Revised Start-up Modeling analysis dated February 11, 2015. The original application reported a NAAQS design value of 293.84 μg/m3 for NO_2. Please rectify the inconsistency and clarify the Class II NO_2 modeling results in the final determination.

DAQ response
The correct number to be put in the table is 171.79 ug/m3, which is based on the revised NO2 analysis. The difference in values is due to two reasons: 1) further refinement of the offsite source as described in pp. 3-9 of the February 11, 2015 Revised Startup Modeling Analysis Report, and 2) utilization of the ARM2 method in AERMOD, which wasn't used in the initial analysis because it wasn't required in order to show compliance with the NAAQS in that analysis.

d. According to page 59 of the Air Permit Review document, the Class II increment analysis was based on a $PM_{2.5}$ major source baseline date of January 6, 1975. For reasons discussed above, the final determination must state that the applicant demonstrated compliance with the $PM_{2.5}$ increment based on an analysis that used the federal 2010 major source baseline date. To ensure compliance with Clean Air Act section 165(a)(3), the 2010 major source baseline date compliance analysis should be used as the basis for NC DENR permit issuance.

DAQ Response
The Permittee has supplied two independent PM2.5 PSD increment analyses; the initial analysis was based on the current federally applicable October 20, 2010 major source baseline date. The second analysis was based on January 6, 1975 major source baseline date. Both analyses were reviewed by the DAQ and show, under either baseline date scenario that the NTE project does not contribute significantly to any exceedances of the PM2.5 Class II Area increment.

4. Additional Air Quality Analysis Comments (also included in the email to Tom Anderson on March 31, 2015.)

a. Modeled NAAQS Compliance Assessment — The following comments are associated with the cumulative NAAQS compliance modeling.

i. The 1-hour NO_2 cumulative compliance modeling resulted in concentrations greater than the NAAQS at 100 receptors. Only the project's contribution to the 8th highest concentration at each receptor was addressed. Although the project did not significantly contribute the 8th highest modeled concentration, the project contribution to all modeled NAAQS exceedances at these receptors must be demonstrated to be less than the SIL. This demonstration was not provided.

DAQ response
Review of the "MAXDCONT" model output files shows that NTE's contribution to ALL modeled cumulative exceedances were insignificant (i.e., less than the NO2 1-hour SIL). The significant contribution analysis examined every multi-year average of the daily maximum 1-hour values for NO2, beginning with the 8th-highest and continuing down the ranked distribution until the cumulative impacts were below the NAAQS. This approach was described on pages 54-55 and 57 of the original modeling report, dated October 22, 2014, for NO2 and PM2.5, respectively. The applicant's modeling protocol described the approach as follows: "[I]n accordance with EPA guidance, the significant contribution analysis will examine every multi-year average of the daily maximum 1-hour values for NO2, beginning with the 8th-highest, continuing down the ranked distribution until all cumulative impacts are below the NAAQS. For the 24-hour PM2.5 analysis, the significant contribution analysis will examine every multi-year average of the maximum 24-hour average values, beginning with the 1st-highest, continuing down the ranked distribution until all cumulative impacts were below the NAAQS." See Modeling Protocol, P. 3-2 (July 30, 2014)

ii. The 24-hour $PM_{2.5}$ cumulative compliance modeling resulted in concentrations greater than the NAAQS at 165 receptors. Only the project's contribution to the 8th highest concentration at each receptor was addressed. Similar to the 1-hour NO_2 cumulative compliance assessment, the project contribution to all modeled NAAQS exceedances at these receptors must be demonstrated to be less than the SIL.

DAQ response
See the first section of the comment to 4.a.i. above - it also applies to PM2.5 as referenced in this comment.

iii. The impact modeling should use the appropriate maximum hourly emission rate associated with the 1-hour NO_2 and 24-hour $PM_{2.5}$ ambient standards. Confirmation is needed that the modeled hourly emissions rates were the appropriate maximum values.

DAQ response
Yes, this has been confirmed by NCDAQ.

b. Receptor Grids — The receptor grid from the property boundary to 2 km has 50-m grid resolution. Grid resolution of 100-m was used from 2 km to 5 km, 500-m resolution from 5 to 10 km, and 1,000-m resolution from 10 to 20 km.

i. The property boundary is indicated to be a fence line. Confirmation is needed that there will not be any uncontrolled through ways (i.e., rail lines or roads without barriers to public assess) within the plant boundary.

ii. All controlling concentrations and modeled concentrations challenging the controlling concentrations (e.g., within 10% of the controlling concentrations) should be modeled to 100-m resolution. All modeled concentrations equal to or greater than the NAAQS and/or the PSD increments should also be modeled to 100-m resolution. Confirmation is needed that these grid resolutions were used for these assessments.

DAQ response
(This comment applies to both items in (b.) above)
It has been confirmed, through review of model output files and graphics, that all max. impact/controlling concentrations were located in areas with 100 meter receptor grid resolution. A dedicated fenceline with controlled access will be provided upon construction of the NTE project.

c. Inventory of Other Nearby Sources — The following comments are associated with the procedures used to develop the modeled inventory of other emission sources.

i. The use of the prevailing wind direction to exclude other emission facilities has not been demonstrated appropriate. Facilities located upwind/downwind of infrequent wind directions can contribute to modeled ambient concentrations. The appropriateness of this procedure for this project should be provided.

DAQ response

As discussed in Sect.8.3 (pp.50-51) of the initial modeling report, this procedure for screening out sources has been discussed in AWMA presentations, EPA workshops, and discussions with several AERMOD model experts. The AQAB believes the approach used by the applicant is reasonable and is supported by others in the modeling community.

ii. The bases (e.g., maximum permitted allowable, annual average, etc.) for the short-term emission rates (*i.e.*, 24-hour or less) in the modeled inventories should be provided. The maximum allowable emissions should be used in the NAAQS and PSD increment compliance modeling. [Note that current actual emissions, if available for inventory sources, can be used in the PSD increment compliance assessment.]

iii. The noted adjustments to the inventory provided information for the emission units/sources should be confirmed appropriate by the applicable regulatory agency and included in that agency's emission inventory.

iv. Because of lack other information, some of the facility inventory adjustments were based on reasonable assumptions. It appears that contacts/discussions with the specific facility personnel for the appropriate information would be appropriate. The reason this source of information was not utilized should be addressed.

DAQ response

(This comment applies to items ii., iii., and iv. above)

The applicant clearly identified adjustments made to the agency-provided emissions inventories in the modeling reports (e.g., Sect. 8.3 of the initial report). NC DAQ confirmed that adjustments made to the Agency-provided inventories were reasonable and based on permitted emissions limitations or sound engineering judgment. For instance, where Agency-provided inventories showed emission rates that were greater than enforceable emissions standards and limitations in the facility permits (such as synthetic minor limits of 100 tpy for criteria pollutants, PSD avoidance limits, etc.) the inventories were adjusted to be consistent with the maximum permitted limits.

v. The inventory of PSD affecting emission units is a subset of the NAAQS emission inventory. For all pollutants except $PM_{2.5}$, the NAAQS emission inventory was conservatively assumed to be the PSD increment affecting inventory. For $PM_{2.5}$, the recent major source baseline date of October 20, 2010 was used in the original application. Although the proposed project is the first PSD permit application in the county, which sets the minor source baseline date (MnSBD), the MnSBD of concern in modeling PSD increment compliance is receptor dependent. Therefore, more than one MnSBD may have to be considered to determine the inventory of emission units affecting PSD increments.

DAQ response

Since October 20, 2010, no major PSD permit applications for PM2.5 have been submitted for Cleveland County or the counties in the vicinity of the proposed project location. This applicant's permit application for a proposed project in Cleveland County is the first PM2.5 PSD permit application submitted for the area since October 20, 2010. The MnBSD has not yet been triggered in the surrounding counties.

d. Significant Impact Level (SIL) - Table 6-1 provides a summary of the ambient air quality standards and impact/monitoring significant concentrations. The Significant Impact Level (SIL) provided for the 1-hour NO_2 is the EPA proposed SIL (7.55 μg/m3). The Revised Start-up Modeling Analysis contained in a February 11, 2015 submittal used the NC DENR SIL of 10 mg/m^3. The reason for the use of two SILs for this project should be explained. In addition, the basis and applicability of the NC DENR 1-hour NO_2 SIL should be provided.

DAQ response

The reason for the difference between the two SILs from the initial analysis and the revised analysis is that the applicant was advised by NCDAQ during discussions regarding the revised analysis that a value of 10 ug/m3 for the NO2 1-hour SIL is currently allowed by NCDAQ versus EPA's proposed value of 7.55 ug/m3. NCDAQ adopted the interim NO2 1-hour SIL in May 2010. The 10 ug/m3 SIL was developed by the Northeast States for Coordinated Air Use Management (NESCAUM) and is based on the ratio of the existing 1-hr CO SIL to the 1-hr CO NAAQS. NC DAQ will continue to use the established, interim SIL until US EPA promulgates a final 1-hour NO2 SIL.

ATTACHMENT B

PRELIMINARY DETERMINATION

NORTH CAROLINA DIVISION OF
AIR QUALITY

Air Permit Review (PSD Preliminary Determination)

Permit Issue Date:

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300383
Inspector's Name: N/A
Date of Last Inspection: N/A
Compliance Code: N/A

Facility Data

Applicant (Facility's Name): Kings Mountain Energy Center

Facility Address:
Kings Mountain Energy Center
180 Gage Road
Kings Mountain, NC 28086

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

Facility Classification: Before: <BFacClass> After: <AFacClass>
Fee Classification: Before: <BFeeClass> After: <AFeeClass>

Permit Applicability (this application only)

SIP: 2D .0503, .0521
NSPS: Subpart Db, IIII, KKKK
NESHAP: Subpart ZZZZ
PSD: Yes
PSD Avoidance:
NC Toxics: Yes
112(r): No
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Michael Green Vice President (904) 687-1857 24 Cathedral Place St. Augustine, FL 32084	Michael Green Vice President (904) 687-1857 24 Cathedral Place St. Augustine, FL 32084	Michael Holzman Senior Advisor (860) 523-8345 57 Mountain View Drive West Hartford, CT 06117

Application Data

Application Number: 2300383.14A
Date Received: 08/01/2014
Application Type: Greenfield Facility
Application Schedule: PSD
Existing Permit Data
Existing Permit Number: <Permit Number>
Existing Permit Issue Date: <XPIssDate>
Existing Permit Expiration Date: <XPExpDate>

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP

<No Inventory>

Review Engineer: Joseph Voelker, P.E.

Review Engineer's Signature: Date:

Comments / Recommendations:
Issue <New Permit Number>
Permit Issue Date:
Permit Expiration Date:

Table of Contents

1. Introduction and Purpose of Application

NTE Carolinas, LLC (NTE) is proposing to construct and operate a natural gas-fired combined-cycle power plant to be known as the Kings Mountain Energy Center (KMEC or Project). The Project will be located near the City of Kings Mountain in Cleveland County, North Carolina (Project Site). The Project will consist of a single power block in a "1x1" combined-cycle multi-shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). The CT and ST will each have separate electric generators. NTE is requesting an Air Quality Permit to Construct/Operate for the following equipment configuration, provided by Mitsubishi Hitachi Power Systems Americas (MHPSA):

- MHPSA M501GAC CT in a 1 x 1 combined-cycle configuration.

A duct burner (DB) will be installed in the HRSG of the proposed new unit. The CT and duct burner will fire pipeline-quality natural gas. The HRSG will be equipped with selective catalytic reduction (SCR) to minimize nitrogen oxide (NOx) emissions and oxidation catalysts to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CT and DB.

The Project will also include several pieces of ancillary equipment. The list of equipment includes:

- One steam turbine (not an emissions source)
- One Auxiliary boiler, natural gas-fired
- Fuel gas heater – natural gas-fired
- CT inlet evaporative cooler (not an emission source)
- Multiple-cell mechanical draft, counter flow, evaporative cooling tower system
- One diesel engine powered emergency generator
- One diesel engine powered fire water pump
- Diesel fuel, lubricating oil and aqueous ammonia storage tanks

Project Emissions
Table 3-11 from the permit application represents the Project's total potential emissions and is reproduced below. The calculation of emissions are presented thoroughly in the application and will not be presented in full detail here. A few items are worth highlighting however.

- A PSD review is triggered for a number of pollutants. Combined-cycle CTs with HRSGs are considered as fossil fuel-fired steam electric plants. Therefore, the applicable PSD threshold for the Project is 100 TPY of potential emissions. Once it is determined that a pollutant exceeds the major source threshold, each of the remaining pollutants is subject to PSD review if the potential to emit (PTE) exceeds the Significant Emission Rates listed in Table 4-3 of the application. Therefore, Project pollutants subject to PSD review are NOx, CO, VOC, PM10, PM2.5, H2SO4 and GHG. The requirements of PSD will be discussed elsewhere in this review.

- By far the primary contributor of each pollutant is from the combustion turbine with duct burner. As such, the following discussion will focus on this source.

The Permittee states in the application that:

> "The emissions calculation procedures used to quantify potential emissions from the Project are based on CT performance and emissions data provided by MHPSA for the CT/HRSG configuration under consideration, other equipment vendor data, engineering estimates, emission limitations specified in applicable New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants, emission factors documented in U.S. Environmental Protection Agency's (EPA) "Compilation of Air Pollution Emission Factors, AP-42" and proposed BACT emission limits. Proposed operating scenarios, including assumptions about the numbers and types of startups and shutdowns, have also been taken into account to develop reasonable, yet conservatively high annual emissions limits for the Project."

The methodologies and calculations were reviewed and this engineer agrees with this statement. Three operating scenarios were evaluated, encompassing the expected range of operating assumptions and numbers of startups and shutdowns. The three cases evaluated are:

- Case A – Mid-range dispatch (approximately 5 days per week, 16 hours per day, 52 weeks per year – total of 270 startups/shutdowns)
- Case B – Base load (approximately 6 days per week, 24 hours per day, 52 weeks per year – total of 80 startups/shutdowns)
- Case C – Potential emissions scenario (8,760 hours of continuous base load operation)

Within each scenario, different assumptions were made for the numbers/types of startups/shutdowns and hours of base load operation. The number of normal operating hours and number of startups/shutdowns in each scenario were multiplied by the emissions rate for the representative CT operating mode. The steady state operating mode emissions were based on average annual ambient conditions. The results of these calculations are presented in Table 3-4 of the application and detailed assumptions and calculations are provided in Appendix C, Table C-4 of the application. The worst case for each pollutant was used to generate the values in Table 3-11 reproduced below.

Further discussion of emissions will be presented in context of the specific regulatory requirements.

Table 3-11 – Total Project Potential Annual Emissions

Potential Emissions (tons/year) – MHPSA M501GAC Combustion Turbine

Emission Unit	NOX	CO	VOC	SO2	PM10	PM2.5	H2SO4	Pb	GHGs (CO2e)	Total HAPs
Combustion Turbine w/ Duct Burner	103.4	243.2	86.9	26.5	65.4	65.4	20.3	0.004	1,676,538	6.6
Diesel Engine-Powered Emergency Generator	5.15	0.66	0.14	0.006	0.05	0.05	8.59E-04	2.9E-05	543	5.74E-03
Diesel Engine-Powered Fire Pump	0.43	0.17	0.017	0.001	0.021	0.02	1.02E-04	4.0E-06	75	1.80E-03
Auxiliary Boiler	3.04	10.21	1.38	0.55	1.93	1.93	6.76E-02	1.3E-04	32,945	0.51
Dew Point Heater	0.43	3.15	0.20	0.08	0.28	0.28	9.66E-03	1.9E-05	4,705	0.07
Cooling Tower					2.57	0.009				
Lubricating Oil Vents			0							
Diesel and Lubricating Oil Tanks			0.0021							
Natural Gas Piping Fugitives									73	
Natural Gas Maintenance + SU/SD Venting									168	
SF6 Circuit Breakers									132.8	
Total Project Emissions	**112.5**	**257.4**	**88.7**	**27.2**	**70.3**	**67.7**	**20.4**	**0.004**	**1,714,806**	**7.2**
Major Source Threshold	100	100	100	100	100	100	100	100	100,000	10/25
Major Source?	Yes	Yes	No	No	No	No	No	No	Yes	No
PSD Significant Net Emission Rate	40	100	40	40	15	10	7	0.6		
Subject to PSD Review?	Yes	Yes	Yes	No	Yes	Yes	Yes	No	Yes	

2. Regulatory review

The Project is subject to a variety of federal and state regulations pertaining to the construction or operation of air emission sources. DENR has the primary jurisdiction over air emissions produced by the Project by enforcing its own regulations as well as EPA's federal requirements. This section summarizes the applicability of various federal and state regulations to the Project. The following regulations and standards were reviewed for applicability to the proposed project:

- National Ambient Air Quality Standards (NAAQS);
- Prevention of Significant Deterioration Regulations;
- Non-Attainment New Source Review Regulations;
- Good Engineering Practice (GEP) Stack Height Regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories;
- Title V Operating Permit Program;
- Acid Rain Program Regulations (ARP);
- Risk Management Program (RMP);
- NOx Budget Trading Program;
- Clean Air Interstate Rule (CAIR);
- Cross-State Air Pollution Rule (CSAPR);
- Mandatory Greenhouse Gas Reporting;
- Greenhouse Gas Tailoring Rule;
- North Carolina Air Quality Rules, 15A NCAC 2D and 2Q; and
- North Carolina State Implementation Plan (SIP)

The applicability of these regulations is discussed at length in the application. Discussion in this review will not attempt to replicate the detail of the application but rather to confirm that all applicable requirements will be met by the Project.

National Ambient Air Quality Standards (NAAQS) (15A NCAC 2D .0400)
Prevention of Significant Deterioration Regulations (15A NCAC 2D .0530)
Non-Attainment New Source Review Regulations; (15A NCAC 2D .0531)
Good Engineering Practice (GEP) Stack Height Regulations; (15A NCAC 2D .0533)

This project will be located in Cleveland County. The attainment status for each criteria pollutant is either unclassifiable or in attainment, hence Non-Attainment New Source Review Regulations do not apply. Compliance with the NAAQS will be determined as required under Prevention of Significant Deterioration Regulations which will be discussed elsewhere in this review document. Good Engineering Practice (GEP) Stack Height Regulations will also be addressed when assessing compliance with all applicable NAAQS.

Title V Operating Permit Program; (15A NCAC 2Q .0500)
Under DENR's Title V Operating Permit regulations (15A NCAC 02Q .0500), a Title V permit is required for Major Stationary Sources. Based on the estimated potential emissions from the Project as presented in Section 3, Table 3-11, the Project will be a Major Stationary Source subject to Title V permitting. During the initial permitting process however, the Permittee has opted for the application to be processed pursuant to 15A NCAC 2Q .0501(c)(2) and 2Q .0504, which allows for the application to be processed under the State permitting rules (2Q .0300) and the PSD rule (2D .0530). The Permittee will then have one year from the date of beginning operation of the facility or source to file an application following the Title V permitting procedures.

Compliance Assurance Monitoring (15A NCAC 2D .0614)
At the subject facility only the combustion turbine with duct burner unit (ID No. ES-1) has "potential pre-control device emissions" of an applicable regulated air pollutant greater than the Title V major source thresholds. The pollutants are NOx, CO and VOC. The unit also has post control NOx and CO emissions greater than Title V major source thresholds and as such is defined as a "large pollutant-specific emissions unit" (PSEU) for both NOx and CO. The NOx emissions however are regulated under NSPS Subpart KKKK and as such are exempted from CAM pursuant to 40 CFR 64.2 (b)(1). Pursuant to 40 CFR 64.5(a)(1), the Permittee will be required to address CAM requirements as part of the initial Title V permitting process.

No further review is necessary at this time.

Risk Management Program (RMP) (15A NCAC 2D .2100)

EPA's Risk Management Plan Rule (RMP), codified in 40 CFR Part 68, requires that facilities with large quantities of highly hazardous chemicals prepare and implement a program to prevent the accidental release of those chemicals. NTE is proposing to use a dilute (19 percent by weight) solution of aqueous ammonia for the SCR NOx control system in lieu of anhydrous or higher concentration aqueous ammonia solutions, which are regulated under RMP if used or stored in amounts greater than 10,000 pounds (anhydrous ammonia) or 20,000 pounds (aqueous ammonia in concentrations of 20 percent or greater). Therefore, the RMP regulations will not be applicable to the Project.

Mandatory Greenhouse Gas Reporting
On October 30, 2009, EPA published in 40 CFR Part 98 Mandatory Greenhouse Gas Reporting requirements. This rule requires facilities that emit greater than 25,000 metric tons per year of CO2e to report their greenhouse gases. Subpart D of 40 CFR Part 98 outlines the requirements for Electricity Generation. The Project will emit more than 25,000 metric tons of CO2e; therefore, greenhouse gas reporting will be required. This is a federally enforceable only requirement. North Carolina does not require the reporting of Greenhouse Gas emissions for emissions inventory purposes.

Other regulations
All remaining regulatory requirements will be discussed on a source by source basis elsewhere in this review.

2.1 Combustion Turbines and Heat Recovery Steam Generator (ID No. ES-1)

The combined-cycle CT/HRSG package incorporates an advanced CT model M501GAC from MHPSA that is similar in design and performance to the current generation commercially available or under development by MHPSA's major competitors. For purposes of developing worst-case Project emission rates and stack parameters and conducting the required regulatory compliance demonstrations, control technology evaluations, and air quality impact analyses for this air permit application, NTE obtained performance and emissions data for the MHPSA M501GAC CT in combined-cycle configuration. All required demonstrations were performed using the worst-case emissions and other specifications from the CT model.

In the combined-cycle process, ambient air is drawn into the compressor element of the CT through an inlet air filtration and silencing system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity to further enhance overall production capability of the CT. After the evaporative cooler section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion stage of the CT. This section of the CT is commonly referred to as the gas generator section. The gas generator is the component that generates criteria and hazardous air pollutant emissions by means of the fuel combustion process.

A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion products (hot gases) expand through the stages of the power turbine where the thermodynamic, or gas energy is converted to mechanical power.

This power is transmitted through rotation of the shaft to the generator for the CT, which is directly coupled to the turbine. The generator takes this rotative power and converts it to electricity.

The hot gases produced in the CT are directed into the HRSG through an exhaust transition duct where waste heat is captured and heat converted into steam energy before the exhaust gases exit the vertical stack for the HRSG. The HRSG contains the natural gas fired duct burners that will be used at times to increase the temperature of the exhaust gases in the HRSG. This is done to maximize output of the steam cycle in the plant.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once the steam does its work in the ST, it is exhausted and condensed at a vacuum in the steam surface condenser. The cycle is a closed loop system as the condensate is reused as feed water to the HRSG. Circulating cooling water from the cooling tower is used to condense the steam in the condenser.

The CT/HRSG is designed to operate up to 8,760 hours per year at 100 percent load firing natural gas, which will be the exclusive fuel used in this equipment. The CT can maintain the emission rates listed in Table 2-1of the application down to a load of approximately 50 percent power. The CT is not expected to operate less than 75 percent of base load for significant periods of time. The DB is also designed for exclusive natural gas firing and typically is operated only when the CT is at 100 percent load.

The source will appear in the permit as follows:

Emission Source ID No.	**Emission source Description**	**Control Device ID No.**	**Control Device Description**
ES-1	One (1) nominal 475 MW natural gas-fired combined-cycle combustion turbine with ductburner (max. heat input HHV = 2,945 MMBtu/hr CT only and 3,603 MMBTU/hr CT + DB). CT Equipped with dry low-NOx combustors.	CD-1A	Selective Catalytic Reduction (SCR)
		CD-1B	CO oxidation catalyst

As mentioned previously this emission source consists of a combustion turbine (CT), heat recovery steam generator (HRSG) equipped with a duct burner (DB) and a steam turbine (ST). Only the CT and DB involve combustion and hence the generation of pollutants. It is also worth noting that the Permittee is not planning (nor requesting) to operate the HRSG and ST independently of the CT). Thus, to simplify the discussion, this aggregate emission source will be referred to as ID No. ES-1. Specific mention to the various components will be made as necessary.

15A NCAC 2D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
This rule limits PM emissions from fuel burning heat exchangers by the following equation:

E = 1.090*(Q)^(-0.2594) Equation 1
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

Pursuant to 2D .0503(e):

> *<u>The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site</u> which are in operation, under construction, or permitted pursuant to 15A NCAC 2Q, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter <u>for each fuel burning indirect heat exchanger.</u>*

For purposes of this rule, there are three fuel burning indirect heat exchangers at the proposed site:

Auxiliary boiler -	138 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Heat recovery steam generator with duct burner (HRSG + DB)	<u>704 MMBtu/hr</u>
Total =	851 MMbtu/hr

Using equation 1 above, the allowable PM emission rate from each of these sources is: 0.19lb/MMBtu. Note that the heat input associated with the CT is not included in the analysis. In a practical sense, since there is only one stack, the CT PM emissions would contribute PM emissions. However, it will be shown that this is not of concern.

Based on the BACT analyses for ES-1 (Section 5.6.6 in the BACT section of this review), the Permittee is requesting the following permit emission limitations for particulate matter:

0.0041 lb/MMBtu, CT only
0.0059 lb/MMBtu, CT + DB

These emission limitations will be enforced through the PSD permit conditions (2D .0530). Given the expected margin of compliance no additional monitoring, recordkeeping and reporting with respect to 2D .0503 will be required.

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
This rule limits visible emissions to no more than 20 percent opacity when averaged over a six-minute period. The combustion of natural gas generally does not result in significant visible emissions. Pursuant to current DAQ policy for natural gas combustion sources no monitoring, recordkeeping or reporting is required for the natural gas-fired in ES-1.

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS
40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60 Subpart KKKK applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu per hour based on the higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005.
The peak load heat input rate of the turbines (without the heat input of DBs) is much greater than 10 MMBtu/hr firing natural gas. Therefore, the Project's CT is subject to this regulation.

Emission Limits for NOx
ES-1 is subject to an emission standard of 15 ppm at 15 percent O2, when fired with natural gas. If the turbine operates at partial load (less than 75 percent of peak load) or if the turbine operates at temperatures less than 0ºF, a NOx limit of 96 ppm at 15 percent O2 will apply. The HRSG will not be operated independently of the CT.

The Project has chosen to comply with concentration-based NOx emission standards. Under the proposed BACT limits to comply with 2D .0530 (PSD), the turbine will reduce its NOx emissions to 2 ppm at 15 percent O2 using low-NOx combustors and selective catalytic reduction while burning natural gas. Therefore, compliance with the NSPS NOx emission limits is expected.

The actual compliance with these emission standards will be verified during the initial performance test and via continuous monitoring with NO2 CEMS.

EmissionLimitsfor SO2
ES-1 will be subject to an emission limit of 0.9 lb/MWh gross output or the turbines must not burn any fuel which contains the total potential sulfur emissions in excess of 0.06 lb SO2/MMBtu heat input.

The Project will comply with the input-based emission standard for SO2. ES-1 will burn only pipeline quality natural gas. Using 0.7 grains sulfur/100 ft3 sulfur content and approximately 1,023 Btu/ft3 (HHV) heat content for natural gas, the SO2 emission rate for ES-1 is estimated as 0.002 lb/MMBtu. Therefore, compliance is demonstrated while firing natural gas, which is the only fuel proposed to be used in ES-1.

15A NCAC 2D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
The following MACTs are potentially applicable to ES-1.

Subpart DDDDD - NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
Subpart YYYY (NESHAP for Stationary Combustion Turbines)
These MACTs are only applicable at major sources of HAPs. This facility is considered to be a minor source of HAPs with a facility-wide PTE of 7.2 tpy for total HAP, which is much less than even the individual HAP threshold of 10 tpy.

Subpart JJJJJJ (NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources)
This MACT is applicable only at minor sources of HAPs and is potentially applicable to HRSG. The HRSG is defined as a waste heat boiler under the rule (even with the added heat from the duct burner), which is also excluded from the definition of a boiler. Therefore, Subpart JJJJJJ is not applicable to the HRSG.

Acid Rain Program Regulations (ARP);
15A NCAC 02Q .0402 ACID RAIN PERMITTING PROCEDURES
The Acid Rain Program is codified in 40 CFR Parts 72 through 78 and implemented by 15A NCAC 02Q .0400. This program aims to reduce acid rain by reduction of SO2 and NOx from utility units that have a nameplate electricity generation capacity greater than 25 MW. This utility unit meets this criterion. However, the unit is not an affected unit under the NOx Emission Reduction Program (40 CFR 76) as it is not a coal-fired utility unit. The permit application expands on the requirements of the acid rain program all of which trigger on the submittal of an Acid Rain Permit application. Pursuant 40 CFR 72.30(a)(2) , the Permittee is required to:

"submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation."

Hence the issuance of this permit does not depend on the requirements of the Acid Rain Program and are not discussed further. A permit condition will be placed into the permit to address this application submittal requirement.

Clean Air Interstate Rule (CAIR) and Cross-State Air Pollution Rule (CSAPR)
CAIR addresses reductions in annual NOx emissions and ozone-season NOx emissions and annual SO2 emissions (as precursors to PM2.5 formation). If subject to CAIR, the Project would be required to submit a permit application at least 18 months before the date on which the unit commences commercial operation (2D .2406 40 CFR 96.121, .221, and .321).

On July 6, 2011 the EPA promulgated the Cross-State Air Pollution Rule (CSAPR) (40 CFR 97 Subparts AAAAA through DDDDD) to replace CAIR, effective January 1, 2012. However, the CSAPR rule implementation has been affected by a number of court actions. Ultimately on October 23, 2014, the U.S. Court of Appeals for the D.C. Circuit ordered that EPA's motion to lift the stay of the Cross-State Air Pollution Rule be granted. CSAPR Phase 1 implementation is now scheduled for 2015.

CSAPR will be implemented by the federal government directly as a Federal Implementation Plan (FIP) (see 40 CFR 52). Thus it is not addressed in North Carolina's State Implementation plan (SIP) and no state rules apply. No further review is necessary at this time. It is anticipated that the CSAPR requirements will be addressed during the initial TV permitting process.

<u>State Enforceable Only</u>
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion elsewhere in this review.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review.

2.2 Auxiliary Boiler (ID No. ES-2)

The auxiliary boiler will be natural gas-fired and operate as needed to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine during warm and hot starts. The auxiliary boiler will have a maximum input capacity of 138 MMBtu/hr, and will be limited to 4,000 hours of operation per year. Potential criteria and HAP emissions are estimated based on vendor-supplied information and natural gas fuel specifications.

The boiler will appear in the air permit as follows:

Emission Source ID No.	Emission source Description	Control Device ID No.	Control Device Description
ES-2	Natural Gas-fired Auxiliary Boiler with Low NOx burners (138 million BTU per hour maximum heat input)	NA	NA

15A NCAC 2D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
This rule limits PM emissions from fuel burning heat exchangers by the following equation:

E = 1.090*(Q)^(-0.2594) Equation 1
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

Pursuant to 2D .0503(e):

> *<u>The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site</u> which are in operation, under construction, or permitted pursuant to 15A NCAC 2Q, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter <u>for each fuel burning indirect heat exchanger.</u>*

For purposes of this rule, there are three fuel burning indirect heat exchangers at the proposed site,

Auxiliary boiler -	138 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Heat recovery steam generator (HRSG) –	<u>704 MMBtu/hr</u>
Total =	851 MMbtu/hr

Using equation 1 above, the allowable PM emission rate from each of these sources is: 0.19lb/MMBtu.

Based on the BACT analyses for these units (Section 5.12.3 of the application), the Permittee is requesting the following permit emission limitations:

Auxiliary boiler -	0.007 lb/MMBtu
Fuel gas heater –	0.007 lb/MMBtu

These emission limitations will be enforced through the PSD permit conditions (2D .0530). Given the expected margin of compliance no additional monitoring, recordkeeping and reporting with respect to 2D .0503 will be required.

15A NCAC 2D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
The boiler will combust natural gas and is subject to the 2.3 pounds per million Btu heat input limitation.
Based upon a maximum sulfur content (permit enforceable) of 0.7 grains /100SCF, the combustion of natural gas is expected to result in SO2 emissions on the order of 0.002 lb/MMBtu. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
The combustion of natural gas usually results (based on experience of other permitted sources at the subject facility and in general) in visible emissions well below the 20% allowed by this rule. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS
40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

As a natural gas-fired boiler with a heat input greater than 100 MMBtu/hr, the proposed auxiliary boiler is subject to Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (NSPS, 40 CFR Part 60, Subpart Db). Although Subpart Db contains emissions standards and/or control requirements for SO2 and PM from boilers combusting coal, oil, wood and other fuels, it contains no SO2 or PM (and opacity) standards applicable to natural gas fired boilers. The most stringent Subpart Db NOX emission standard applicable to gas fired boilers with a low heat release rate is 0.1 lb/MMBtu. The Project's auxiliary boiler will be designed and operated in accordance with the applicable Subpart Db NOx emission standard.

The proposed NOx emission rate (0.011 lb/MMBtu, BACT) will easily meet the applicable emission standard. NTE will also comply with the applicable monitoring, record keeping and reporting requirements consistent with Subpart Db. The Permittee has requested, in lieu of CEMS, to monitor steam generation pursuant to 40 CFR 60.49b(c).

15A NCAC 2D .1111 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
40 CFR 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Since the Project will be a minor source of HAPs, this rule was reviewed for applicability to the Project's auxiliary boiler. The auxiliary boiler is defined as a gas-fired boiler, which is specifically exempted from this subpart in accordance with § 63.11195(e). Since it is not permitted to burn other fuels which do have requirements under this rule, no potential compliance issues are expected and hence no monitoring, recordkeeping and reporting is necessary to ensure compliance with this rule. No further review is necessaryTherefore, Subpart JJJJJJ is not applicable to the auxiliary boiler.

<u>State Enforceable Only</u>
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion elsewhere in this review.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review.

2.3 Fuel Gas Heater (ID No. ES-3)

The natural gas-fired fuel gas heater will operate as necessary to condition the natural gas prior to combustion to prevent condensation. The maximum rated capacity of the fuel gas heater will be 9 MMBtu/hr and will have the potential to operate for 8,760 hours per year at maximum capacity. Potential criteria and HAP emissions are estimated based on vendor-supplied information and natural gas fuel specifications.

The heater will appear in the air permit as follows:

Emission Source ID No.	**Emission source Description**	**Control Device ID No.**	**Control Device Description**
ES-3	Natural Gas-fired Fuel Gas Heater (9 million BTU per hour maximum heat input)	NA	NA

15A NCAC 2D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
See the analysis presented for the auxiliary boiler.

15A NCAC 2D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
The fuel gas heater will combust natural gas and is subject to the 2.3 pounds per million Btu heat input limitation.
Based upon a maximum sulfur content (permit enforceable) of 0.7 grains/100SCF, the combustion of natural gas is expected to result in SO2 emissions on the order of 0.002lb/MMBtu. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
The combustion of natural gas usually results (based on experience of other permitted sources at the subject facility and in general) in visible emissions well below the 20% allowed by this rule. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS
40 CFR Part 60, Subpart Dc, New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units is potentially applicable to this source. However, the source has a heat input capacity of less than 10 million Btu per hour, the applicability threshold pursuant to 40 CFR 60.40c(a). Thus, this rule does not apply.

15A NCAC 2D .1111 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
40 CFR 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Since the Project will be a minor source of HAPs, this rule was reviewed for applicability to the Project's fuel gas heater. The proposed fuel gas heater is defined as a process heater under this subpart, which is excluded from the definition of a boiler. Since this rule only addresses boilers as defined at 40 CFR 63.11237, this rule does not apply to the fuel gas heater. No further review is necessary.

2.4 Internal Combustion Engines (ID Nos. ES-4 and ES-5)

The Permittee is requesting the construction and operation of a diesel engine powered emergency generator and a diesel engine powered fire water pump. The fire water pump will be used for emergency purposes in the event of a fire and for routine operations and testing as required by the National Fire Prevention Association (NFPA) Code. The emergency diesel fire pump is rated at a maximum 260 BHP. The emergency diesel engine powered standby generator, rated at 1,250 kilowatts (kW), will allow maintenance of vital plant loads during power outages or maintenance on the switchyard.

The diesel engine generator and fire pump will only be operated during power interruptions to provide emergency power, lighting, and fire protection when the Project CT is not operating and at most once per week for less than 30 minutes for operational testing purposes when the CT is operational.

The Project is proposing to accept operating restrictions on the emergency generator and fire pump through the air quality permit that would limit annual cumulative non-emergency operation (e.g., engine testing) to less than 100 hours per consecutive 12-months for each engine. The 100-hour operational restriction for each engine would not apply towards operation during actual emergency situations. *NSPS IIII, which applies to both engines, includes a 50 hour operation limitation outside of non-emergency* *service and an overarching 100 hour operation limitation covering the 50 hour non-emergency service limitation, maintenance checks and readiness testing, emergency demand response and periods of voltage deviations in the electrical supply.*

Potential emissions from each emergency diesel engine have been estimated based on 500 hours per year of operation consistent with EPA (and NCDAQ) policy.

Ultra-low sulfur (15 ppm by weight sulfur) diesel fuel will be used in both the fire water pump and standby generator engines. An approximate 5000-gallon diesel storage tank will be located on site to supply diesel fuel for the two diesel engines. In addition, a 300-gallon day tank will be used for the diesel fire water pump. (Fuel will be transferred from storage to the day tank and the diesel fire water pump will take suction directly from the day tank).

These sources will appear in the air permit as follows:

Emission Source ID No.	Emission source Description	Control Device ID No.	Control Device Description
ES-4	Diesel Fuel-fired Standby Emergency Generator (1,850 maximum brake horsepower)	NA	NA
ES-5	Diesel Fuel-fired Emergency Fire Pump Engine (260 maximum brake horsepower)	NA	NA

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS 40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, promulgated July 11, 2006 and amended June 28, 2011, will apply to the emergency fire pump engine and the emergency standby generator proposed for the Project. The rule requires manufacturers of such engines to meet emission standards that are phased in for the size, type of engine application, and model year of the engine. Owners and operators of covered engines are required to configure, operate, and maintain the engines according to specifications and instructions provided by the engine manufacturer and to maintain records demonstrating compliance. Diesel engines subject to Subpart IIII must meet the ultra-low sulfur content standard specified in 40 CFR Part 80.510(b) of 15 ppm. Emergency engines also must install an hour-meter and track hours of operation in emergency and non-emergency service. The Project will comply with the requirements applicable to owners and operators of covered engines.

Because the exact diesel engines have not been specified (and will not be until the Project goes out for bid), NTE is requesting permit conditions that limit the maximum size and emissions to the engines specified in the air permit application, require purchase of Tier 2 certified diesel engines, and require submittal of EPA compliance documentation to DENR when the engines are purchased.

The permit will include all the requirements of NSPS IIII applicable to these engines.

15A NCAC 2D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY - 40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

The proposed diesel engine-powered emergency generator and fire water pump are subject to Subpart ZZZZ, since this standard is applicable to both major and non-major (Area) sources of HAPs. However, in accordance with 40 CFR 63.6590(c), new or reconstructed compression ignition engines at Area sources must meet the requirements of 40 CFR 60 Subpart IIII to comply with requirements of Subpart ZZZZ. No other requirements apply under Subpart ZZZZ.

The permit will contain a permit condition that indicates that compliance with the applicable requirements of NSPS IIII will indicate compliance with Subpart ZZZZ.

15A NCAC 2D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Under this rule, the combustion sources are subject to a SO2 emission limit of 2.3 pounds per million Btu heat input.

However, 2D .0516 states:

> *(b) A source subject to an emission standard for sulfur dioxide in Rules .0524, .0527, .1110, .1111, .1205, .1206, .1210, or .1211 of this Subchapter shall meet the standard in that particular rule instead of the standard in Paragraph (a) of this Rule.*

These engines are subject to 2D .0524 NSPS Subpart IIII which has a more stringent sulfur standard. Thus, this rule does not apply to these emergency engines.

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
Under this rule, each source is subject to a 20 percent opacity limit when averaged over a 6-minute period (with some exceptions).

However, 2D .0521(b) states (paraphrased):

> *(b) Scope. This Rule shall apply to all fuel burning sources and to other processes that may have a visible emission. However, sources subject to a visible emission standard in Rules .0506, .0508, .0524, .0543, .0544, .1110, .1111, .1205, .1206, .1210, .1211, or .1212 of this Subchapter shall meet that standard instead of the standard contained in this Rule.*

These engines are subject to 2D .0524 NSPS Subpart IIII which has a "smoke" standard. Thus, this rule does not apply to these emergency engines.

State Enforceable Only
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS
See discussion elsewhere in this review.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review.

2.5 Cooling Tower (ID No. ES-6)

The steam produced in the Heat Recovery Steam Generator (HRSG) is used in the Steam Turbine (ST) to produce additional electrical power. Once the steam does its work in the ST, it is exhausted and condensed at a vacuum in the steam surface condenser. The cycle is a closed loop system as the condensate is reused as feed water to the HRSG. Circulating cooling water from the cooling tower is used to condense the steam in the condenser.

The cooling towers will operate continuously when the CT is operated. The cooling towers will emit small amounts of PM emissions associated with wet cooling tower drift losses. Drift loss will be minimized with high-efficiency drift eliminators.

The cooling tower will appear in the air permit as follows:

Emission Source ID No.	Emission source Description	Control Device ID No.	Control Device Description
ES-6	Multi-cell cooling tower (175,000 gallon per minute maximum reticulating flow rate)	CD-6	Mist eliminator (0.0005 percent drift loss)

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
Cooling towers are sources of PM emissions and hence potentially visible emissions. However, the visible emissions are primarily the result of the water droplets themselves. EPA Reference Method 9 is used to determine compliance with visible emission limitations (expressed as a percent opacity). The method provides for opacity determination "beyond the point in the plume at which condensed water vapor is no longer visible."

Based on the actual performance of other cooling towers, the opacity as determined by Method 9 is expected to be essentially 0%. Therefore, consistent with current DAQ policy, no monitoring, recordkeeping and reporting will be required.

15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See discussion elsewhere in this review.

3. 15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

The PSD regulations are designed to ensure that the air quality in current attainment areas does not significantly deteriorate beyond baseline concentration levels. PSD regulations specifically apply to the construction of EPA-defined Major Stationary Sources in areas designated as attainment or unclassified attainment for at least one of the criteria pollutants. North Carolina has incorporated EPA's PSD regulations (40 CFR 51.166) into its air pollution control regulations in 15A NCAC 02D .0530.

Combined-cycle CTs with HRSGs are considered as fossil fuel-fired steam electric plants. Therefore, the applicable PSD threshold for the Project is 100 TPY of potential emissions. Once it is determined that a pollutant exceeds the major source threshold, each of the remaining pollutants is subject to PSD review if the potential to emit (PTE) exceeds the Significant Emission Rates listed in Table 4-3 of the application. Therefore, Project pollutants subject to PSD review are NOx, CO, VOC, PM10, PM2.5, H2SO4 and GHG.

The elements of a PSD review are as follows:

1) A Best Available Control Technology (BACT) Determination as determined by the permitting agency on a case-by-case basis in accordance with 40 CFR 51.166(j),
2) An Air Quality Impacts Analysis including Class I and Class II analyses, and
3) An Additional Impacts Analysis including effects on soils and vegetation, and impacts on local visibility in accordance with 40 CFR 51.166(o).

Best Available Control Technology (BACT) Determination

Under PSD regulations, the basic control technology requirement is the evaluation and application of BACT. BACT is defined as follows [40 CFR 51.155 (b)(12)]:

An emissions limitation...based on the maximum degree of reduction for each pollutant... which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.

As evidenced by the statutory definition of BACT, this technology determination must include a consideration of numerous factors. The structural and procedural framework upon which a decision should be made is not prescribed by Congress under the Act. This void in procedure has been filled by several guidance documents issued by the federal EPA. The only final guidance available is the October 1980 "Prevention of Significant Deterioration – Workshop Manual." As the EPA states on page II-B-1, "A BACT determination is dependent on the specific nature of the factors for that **particular case**. The depth of a BACT analysis should be based on the quantity and type of pollutants emitted and the **degree of expected air quality impacts**." (emphasis added). The EPA has issued additional DRAFT guidance suggesting the use of what they refer to as a "top-down" BACT determination method. While the EPA Environmental Appeals Board recognizes the top-down approach for delegated state agencies,[1] this procedure has never undergone rulemaking and as such, the process is not binding on fully approved states, including North Carolina.[2] The Division prefers to follow closely the statutory language when making a BACT determination and therefore bases the determination on an evaluation of the statutory factors contained in the definition of BACT in the Clean Air Act. As stated in the legislative history and in EPA's final October 1980 PSD Workshop Manual, each case is different and the State must decide how to weigh each of the various BACT factors. North Carolina is concerned that the application of EPA's DRAFT suggested a top-down process will result in decisions that are inconsistent with the Congressional intent of PSD and BACT. The following are passages from the legislative history of the Clean Air Act and provide valuable insight for state agencies when making BACT decisions.

> The decision regarding the actual implementation of best available technology is a key one, and the **committee places this responsibility with the State**, to be determined on a case-by-case judgment. It is recognized that the phrase has broad flexibility in how it should and can be interpreted, depending on site.
>
> In making this key decision on the technology to be used, the State is to take into account energy, environmental, and economic impacts and other costs of the application of best available control technology. **The weight to be assigned to such factors is to be determined by the State**. Such a flexible approach allows the adoption of improvements in technology to become widespread far more rapidly than would occur with a uniform Federal

[1] See, http://es.epa.gov/oeca/enforcement/envappeal.html for various PSD appeals board decisions including standard for review.
[2] North Carolina has full authority to implement the PSD program, 40 CFR Sec. 52.1770

> standard. The only Federal guidelines are the EPA new source performance and hazardous emissions standards, which represent a floor for the State's decision.
>
> This directive enables the State to consider the size of the plant, the increment of air quality which will be absorbed by any particular major emitting facility, and such other considerations as anticipated and desired economic growth for the area. This allows the States and local communities judge how much of the defined increment of significant deterioration will be devoted to any major emitting facility. If, under the design which a major facility proposes, the percentage of increment would effectively prevent growth after the proposed major facility was completed, the State or local community could refuse to permit construction, or limit its size. **This is strictly a State and local decision; this legislation provides the parameters for that decision.**
>
> One of the cornerstones of a policy to keep clean areas clean is to require that new sources use the best available technology available to clean up pollution. One objection which has been raised to requiring the use of the best available pollution control technology is that a technology demonstrated to be applicable in one area of the country in not applicable at a new facility in another area because of the differences in feedstock material, plant configuration, or other reasons. **For this and other reasons the Committee voted to permit emission limits based on the best available technology on a case-by-case judgment at the State level.** [**emphasis added**]. This flexibility should allow for such differences to be accommodated and still maximize the use of improved technology.
>
> Legislative History of the Clean Air Act Amendments of 1977.

The BACT analysis provided by NTE for the proposed Project was conducted <u>consistent with the above definition as well as EPA's five step "top-down" BACT process</u>. The "top down" methodology results in the selection of the most stringent control technology in consideration of the technical feasibility and the energy, environmental, and economic impacts. Control options are first identified for each pollutant subject to BACT and evaluated for their technical feasibility. Options found to be technically feasible are ranked in order of their effectiveness and then further evaluated for their energy, economic, and environmental impacts. In the event that the most stringent control identified is selected, no further analysis of impacts is performed. If the most stringent control is ruled out based upon economic, energy, or environmental impacts, the next most stringent technology is similarly evaluated until BACT is determined.

After establishing the baseline emissions levels required to meet any applicable NSPS, NESHAPs, or SIP limitations, the "top-down" procedure followed for each pollutant subject to BACT is outlined as follows:

- Step 1: Identify of all available control options - from review of EPA RACT/BACT/LAER Clearinghouse (RBLC), agency permits for similar sources, literature review and contacts with air pollution control system vendors.
- Step 2: Eliminate technically infeasible options - evaluation of each identified control to rule out those technologies that are not technically feasible (i.e., not available and applicable per EPA guidance).
- Step 3: Rank remaining control technologies - "Top-down" analysis, involving ranking of control technology effectiveness.
- Step 4: Evaluate most effective controls and document results – Economic, energy, and environmental impact analyses are conducted if the "top" or most stringent control technology is not selected to determine if an option can be ruled out based on unreasonable economic, energy or environmental impacts.
- Step 5: Select the BACT – the highest-ranked option that cannot be eliminated is selected, which includes development of an achievable emission limitation based on that technology.

NTE also considered case-by-case considerations, achievability in practice and redefining the source as fully explained in the permit application.

To facilitate cross referencing, the BACT analysis as presented in this review document will maintain the section/paragraph numbering scheme contained in the submitted application. Much of the language will be excerpted directly in abbreviated form from the application with additional narrative provided by the DAQ. As such, the language included in this review can be considered representative of opinions of the DAQ.

5.1.2.4 Identification of Potential Control Technologies

Potentially applicable emission control technologies were identified by researching the EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC, a database made available to the public through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

Searches of the RBLC database were performed in February 2014 to initially identify the emission control technologies and emission levels that were determined by permitting authorities as BACT or LAER within the past ten years for emission sources comparable to the proposed combined-cycle CT. The Large Combined Cycle and Cogeneration Natural Gas-Fired Turbines (RBLC Code 15.210) category was searched.

Upon completion of the RBLC search, relevant vendor information, pending permit applications, and issued permits not included in the RBLC were also reviewed. Sources of information searched included EPA Region IV's National Combustion Turbine List, California Air Resources Board (CARB) BACT Clearinghouse, state air quality agency websites, New Jersey's State of the Art (SOTA) Manual for Stationary Combustion Turbines and other sources. Appendix D of the application presents summary tables of relevant BACT and LAER determinations for combined-cycle CTs firing natural gas, by pollutant.

Additional RBLC searches were performed to identify control options for the auxiliary equipment as permitted within the past ten years. The following categories were searched:

- Diesel Internal Combustion Engines less than or equal to 500 hp (RBLC Code 17.210)
- Diesel Internal Combustion Engines greater than 500 hp (RBLC Code 17.110)
- Industrial-size natural gas-fired boilers (RBLC Code 12.310)
- Commercial/Institutional-size natural gas-fired boilers (RBLC Code 13.310)
- Miscellaneous sources – for cooling towers (RBLC Code 99.999)

Although the accuracy of <u>all</u> the information provided above was not independently verified by the DAQ, a review of the RBLC database support the claims with respect to stringency and representativeness of the BACT proposed for the Project.

3.1 BACT for Combustion Turbine and Duct Burner (ID No. ES-1)

3.1(5.2) BACT for CT Nitrogen Oxides (NOx)

5.2.1 Minimum NOx Regulatory Requirements

The NSPS (Subpart KKKK) limits applicable to NOx emissions from natural gas-fired combined-cycle CTs are as follows:

- 15 ppm @ 15 percent O2 or 0.43 lb/MWh, when fired with natural gas
- 96 ppm @ 15 percent O2 or 4.7 lb/MWh, if the turbines operate at partial load (less than 75 percent of peak load) or if the turbines operate at temperatures less than 0 ºF
- 54 ppm @ 15 percent O2 or 0.86 lb/MWh, applicable to the HRSG, if operated independently of the CT

5.2.2 Identification of Available NOx Control Technologies (Step 1)

NOx is formed during the combustion of fuel and is generally classified as either thermal NOx or fuel NOx and is fully described in the permit application.

Reduction in NOx formation can be achieved using combustion controls and/or flue gas treatment (post-combustion controls). Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, the following combustion and post-combustion controls were identified for further evaluation:

Combustion control options include:

- Fuel Selection (fuel-NOx control)
- Water/Steam Injection
- Dry Low-NOx Combustors
- Catalytic Combustion (XONON)

Post-combustion control options include:

- Selective Catalytic Reduction (SCR)
- $EM_X/SCONO_X$
- Selective Non-Catalytic Reduction (SNCR)

5.2.2.1 Fuel Selection (Fuel-NOx Control)

During the combustion process, oxides of nitrogen are formed in the high temperature region of the flame by the fixation of atmospheric nitrogen (thermal NOx) and by oxidation of nitrogen contained in the fuel (fuel NOx).

Various fuels combust at different temperatures, have different amounts of fuel-bound nitrogen, and, therefore, result in inherently different NOx formation. Fuels that have been used in CTs include natural gas, methane, propane, process off-gas (such as refinery mix), jet fuel (kerosene), distillate oil, and methanol. Natural gas burns at a lower flame temperature than do any of the other fuels, except perhaps process gas, resulting in lower thermal-NOx generation. Gaseous fuels and methanol have essentially no nitrogen component and, therefore, no fuel NOx. The Project CT and DB will be fueled exclusively with natural gas.

5.2.2.2 Water/Steam Injection (WI)

Injection of either water or steam as a diluent directly into the combustor lowers the flame temperature and thereby reduces thermal NOx formation. Although common in oil firing, WI is typically not used for natural gas firing, as uncontrolled NOx emissions are less due to negligible nitrogen content of natural gas. WI results in control efficiencies on the order of 80 to 85 percent for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below. CO and VOC emissions are relatively low for most CTs. However, WI may increase emissions (water more than steam) of both of these pollutants.

5.2.2.3 Dry Low-NOx (DLN) Combustor

Lean pre-mix or DLN combustors are designed to control peak combustion temperature, combustion zone residence time and combustion zone free oxygen, thereby minimizing thermal NOx formation. Various methods used by DLN combustor designs are fully explained in the application.

DLN combustors have been employed successfully for natural gas-fired CTs for more than fifteen years. DLN combustors can achieve NOx emissions as low as 9 ppm for frame-size turbines.

5.2.2.4 Catalytic Combustion (XONON)

Catalytic combustors, marketed under trade names such as XONON™, use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NOx formation. XONON™ uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst.

The technology was first designed into the combustor of a 1.4 MW gas turbine at Silicon Valley Power in Santa Clara, California in 1999. Since its installation, the turbine has operated as a demonstration of the technology's performance. The California EPA's Air Resources Board (CARB) evaluated NOx and CO CEMS data and concluded that the technology achieved a NOx level of 2.5 ppmvd @ 15 percent O2 and a CO level of 6.0 ppmvd @ 15-percent O2 The CARB report also summarizes commercial installations at five other 1.4 MW CTs with permit limits ranging from 3 to 20 ppmvd @ 15 percent O2.

5.2.2.5 Selective Catalytic Reduction (SCR)

SCR is a post-combustion flue-gas treatment technology for reducing NOx that involves injection of ammonia (NH3), a reducing agent, into the flue gas downstream of the CT and then passing the gas through a catalyst bed and is fully described in the application. SCR is the most widely used post-combustion NOx control technique on utility-scale CTs, usually in conjunction with combustion controls. It has been demonstrated to be able to achieve NOx emission limits as low as 2.0 ppm and up to 90 percent reduction efficiency.

5.2.2.6 EM_X/$SCONO_X$

Goal Line Environmental Technologies developed $SCONO_X$, which was developed to simultaneously remove NOx, CO, VOC, and SO_X without supplemental reagent. The technology is currently licensed to EmeraChem Power™ and the current version of the technology is marketed as EMx™. EMx™ uses a platinum-based catalyst coated with potassium carbonate to oxidize CO to CO2 and NO to NO2 and is fully described in the application.

One advantage of the EMx™ process, compared to SCR, is that ammonia is not required. However, the EMx™ catalyst must be recoated, or "washed" every 6 months to one year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the catalyst.

The technical feasibility and commercial availability of EMx™ technology as BACT or LAER for large CT projects have been raised at numerous air permitting proceedings. The general conclusion has been that although EMx™ may have some advantage over SCR in being a zero ammonia NOx reduction process, both SCR (combined with oxidation catalysts) and EMx™ are capable of achieving equivalent levels of controlled NOx, CO, and VOC emissions. Other proceedings have concluded simply that EMx™ is not currently available for the size CT proposed for the Project. The technology has been demonstrated on combustion turbines up to a 45 MW unit.

In addition, the cost impact of EMx™ is considered significantly higher than that for the combination of SCR and oxidation catalysts as shown in Table 5-2 of the application and reproduced here:

Table 5-2 – Cost Comparison between SCR and EMx™ for a 500-MW CT Power Plant

Capital Cost		Annual O&M Cost	
SCR/CO Cat.	EMx™	SCR/CO Cat.	EMx™
$6,259,857	$20,747,637	$1,355,253	$3,027,653

5.2.2.7 Selective Non-Catalytic Reduction (SNCR)
Selective non-catalytic reduction (SNCR): Selective non-catalytic reduction involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600°F to 2,100°F and is most commonly used in external combustion boilers. SNCR requires a temperature window that is higher than the exhaust temperatures from utility CT installations (including this one). The exhaust temperature from the proposed CTs ranges from approximately 1,030°F to 1,170°F; therefore, SNCR is not technically feasible in this application.

5.2.3 Elimination of Technically Infeasible Options (Step 2)
The technical feasibility of the identified available CT NOx control options is summarized as follows:

Fuel Selection/Fuel-NOx Control - Exclusive use of natural gas is technically feasible for the Project, given its location in proximity to developing natural gas supply lines, and is being proposed. Higher NOx emissions resulting from use of distillate oil as a backup fuel will be avoided through exclusive use of natural gas.

Water/Steam Injection - Wet injection, although less effective for gas firing than other combustion systems (e.g., DLN combustors), is considered technically feasible; however, in modern combined-cycle units, wet injection is only used with oil firing, which is not proposed for the Project. Because wet injection is not used in modern gas-fired combined-cycle units and since DLN combustors would provide an equivalent or higher level of control, wet injection is not carried forward for further analysis.

Dry Low NOx (DLN) Combustors - DLN combustors are available, demonstrated, and technically feasible for CT units in either simple cycle or combined-cycle configurations. The CT proposed for the Project utilizes DLN technology, controlling NOx to a concentration of 15 ppmvd at 15 percent O_2 in the CT exhaust gas (before the HRSG). As the Project will also be exclusively fired with natural gas, DLN will be used for all Project operating scenarios.

Catalytic Combustion - Application of XONON™ catalytic combustion system to a large combined-cycle CT unit has not been demonstrated. All commercial installations to date have been on small turbines in the 1-2MW size range. For this reason, the XONON™ technology is not considered available or technically feasible for the proposed Project CT unit.

SCR - SCR has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed Project's combined-cycle CT.

EMx™ - Because EMx technology has not yet been demonstrated on large, commercial-scale CTs, this technology is determined to be technically infeasible for the proposed Project. Moreover, SCR and EMx™ are considered capable of achieving equivalent levels of controlled NOx, CO, and VOC emissions.

SNCR - Because the exhaust temperatures from the proposed combined-cycle units typically will not approach the operating temperature window for SNCR, this technology is not technically feasible for this application. Further, a review of EPA's RBLC database and discussions with control technology vendors do not indicate that SNCR systems have been successfully installed for combined cycle CTs. Based on the above limitations, SNCR is considered technically infeasible for application to the CT in this Project.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Fuel Selection – exclusive natural gas;
- DLN Combustors; and
- SCR

5.2.4 Ranking of Remaining Control Technologies (Step 3)
Exclusive natural gas use, DLN combustors, and SCR are compatible technologies and considered together, represent the best control strategy for NOx emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.2.5 Evaluation of Most Effective Controls (Step 4)
Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy, and environmental impacts are only required if the "top" or most stringent control technology is not selected to determine if an option can be ruled out based on unreasonable impacts. In this case, the top technologies are specified.

5.2.6 Selection of BACT and Determination of NOX Emission Limit (Step 5)
NTE proposes a combination of exclusive natural gas use, DLN combustors, and SCR to meet BACT requirements. These technologies, when considered together, represent the most stringent NOx controls available for combined-cycle CTs. NTE proposes a NOx emission limit of 2.0 ppmvd @ 15 percent O2, to be achieved at all operating loads between 50 and 100 percent, with or without duct firing in the HRSG. NTE proposes to meet these limits on a 1-hour average basis. (A discussion of alternative limits during startup and shutdown events is provided in Section 5.9).

Based on a review of LAER and BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, the 2.0 ppmvd @ 15 percent O2 NOX level has been identified as the most-stringent limit contained in a current air permit for a large combined-cycle CT. A summary of LAER and BACT determinations for NOx emission from combined-cycle CTs permitted since January 2004, presented in Appendix D, Table D-1 of the application, indicates 39 CTs that have a NOx limit of 2.0 ppmvd @ 15 percent O2. The averaging time basis of these limits, where listed, varies from 1-hour to 24-hours. A number of the most-recently issued permits (Russell City Energy Center (California), Dominion Energy Warren (Virginia), Kleen Energy Systems, Middletown (Connecticut), Moxie Liberty and Patriot (Pennsylvania), Oregon Clean Energy (Ohio) and Footprint Power Salem (Massachusetts)) each reference a 1-hour averaging time basis. Of these permits containing a 1-hour average basis for the NOx limit, the Kleen Energy Systems project began operations in the summer of 2011 and the Russell City Energy project began commercial operations in August 2013. The remaining facilities are in various stages of construction. The 2.0 ppmvd @ 15 percent O2 limit based on a 1-hour averaging time is considered the most stringent limit in any permit for a large combined-cycle CT.

The DAQ agrees that the proposed NOx emission limit is equivalent to the most stringent identified limit and is more stringent than applicable NSPS or North Carolina SIP limits for the same class or category of emission sources, and that it is sufficiently demonstrated as BACT.

3.1(5.3) BACT for CT CO
CO emissions from the Project are subject to BACT requirements.

5.3.1 Minimum CO Regulatory Requirements
There are no applicable NSPS, NESHAPs or North Carolina SIP requirements applicable to CO emissions from combined-cycle CTs.

5.3.2 Identification of Available CO Control Technologies (Step 1)
CO emissions are formed in CTs as a result of incomplete combustion of carbonaceous fuels and is fully described in the application. Providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion can minimize CO emissions. However, these combustion techniques can sometimes increase NOx emissions. Therefore, a compromise must be reached whereby the flame temperature reduction is set to achieve the lowest NOx emission rate possible while maintaining CO emission rates at acceptable levels.

There are two basic techniques for controlling CO emissions from combustion units: good combustion practices and post-combustion controls – installation of oxidation catalysts in the HRSG to oxidize CO to CO2. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, oxidation catalysts have been applied extensively over the last 10 years for CO control.

5.3.2.1 Combustion Controls
CO emissions are generated from the incomplete combustion of carbon in the fuel and organic compounds. Optimization of the combustion chamber designs and operation to improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering CO emissions. This process is often referred to as combustion controls. Combustion controls in large CTs generally utilize "lean combustion" (large amount of excess air) to produce a cooler flame temperature to minimize NOx formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion, thus minimizing CO emissions.

5.3.2.2 Oxidation Catalysts
Oxidation catalysts are a proven post-combustion control technology widely in use on large CTs to abate CO emissions. An oxidation catalyst oxidizes the CO in the exhaust gases to form CO2. No supplementary reactant is necessary in conjunction with the catalyst for the oxidation reaction to proceed. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM10, PM2.5 and sulfuric acid mist emissions (from oxidation of SO2 to SO3, followed by conversion of SO3 to H2SO4 in the presence of moisture). Other aspects of oxidation catalysts are fully described in the application. Oxidation catalysts have been employed successfully for two decades on natural gas-fired CTs. An oxidation catalyst is considered to be technically feasible for application to this Project.

5.3.2.3 EMx™

The EMx™ system previously described in Section 5.2.2.6 also controls VOC. The EMx™ system employs a single catalyst to simultaneously oxidize CO and VOC to CO2 and NO to NO2.

5.3.3 Elimination of Technically Infeasible Options (Step 2)
The technical feasibility of the identified available CT CO control options is summarized as follows:

Combustion controls. Combustion controls have been demonstrated successfully in numerous applications and is considered technically feasible for the proposed Project's combined-cycle CT.

Oxidation Catalysts. Catalytic oxidation has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed Project's combined-cycle CT.

EMx™. As previously discussed in Section 5.2.3, the EMx™ control technology is not considered available (and therefore is considered technically infeasible) because it has not been commercially demonstrated on large combined-cycle CT units.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Combustion controls; and
- Oxidation catalysts.

5.3.4 Ranking of Remaining Control Technologies (Step 3)
Combustion controls and catalytic oxidation are compatible technologies and considered together, represent the best control strategy for CO emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.3.5 Evaluation of Most Effective Controls (Step 4)
Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy, and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for CO.

5.3.6 Selection of BACT and Determination of CO Emission Limits (Step 5)
NTE proposes a combination of combustion controls, and oxidation catalysts to meet BACT requirements for CO. These technologies, when considered together, represent the most stringent CO controls available for combined-cycle CT. The proposed CO emission limits are summarized below for normal operating loads between 50 and 100 percent. NTE proposes to meet the CO limit on a 1-hour average basis (with CEMS). (A discussion of alternative limits during startup and shutdown events is provided in Section 5.9).

<u>MHPSA M501GAC (50 – 100 Percent Load)</u>:

CO	2.0 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/out duct firing
	2.0 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/ duct firing

Based on a review of BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, the majority of recent CO BACT determinations include combustion controls and oxidation catalysts. The most stringent recent limits on projects that are in operation are 2.0 ppmvd @ 15 percent O2 for CO. Summaries of BACT determinations for CO emissions from combined-cycle CTs permitted since January 2004 are presented in Appendix D, Table D-2. A review of CO permit limits indicates that 20 large combined-cycle CT projects have been permitted with a CO limit of 2.0 ppmvd @ 15 percent O_2. The most stringent averaging time basis for these limits is 1-hour; however, several at the 2.0 ppm level are based on a 3-hour average. There have also been six recent permits (Brunswick Power, Dominion Warren, Avenal, Palmdale, Kleen Energy Systems, and Southern Company McDonough) permitted at less than 2.0 ppm CO. The permitted CO limits, all corrected to 15 percent O_2 are 1.8 ppm for McDonough, 1.5 ppm for Brunswick, Warren (without duct firing, 2.4 ppm with duct firing), Avenal (2 ppm with duct firing) and Palmdale (2 ppm with duct firing) and 0.9 ppm for Kleen (1.7 ppm with duct firing). The Brunswick and Warren are currently under construction, with Warren scheduled to begin operation in late 2014 or early 2015. The Avenal and Palmdale facilities have not yet started construction. The McDonough units began operating in 2012 and Kleen Energy started up in the summer of 2011. As such, there is insufficient long-term operating history at this time to support feasibility a CO limit less than 2.0 ppmvd @ 15 percent O_2 on a 1-hour averaging basis to consider it demonstrated in practice. Therefore, the 2.0 ppmvd @ 15 percent O_2 limit based on a 1-hour averaging time is considered the most stringent CO limit achieved in practice for a large combined-cycle CT.

The DAQ agrees that the proposed CO emissions limits are equivalent to the most stringent identified limits that are considered achieved in practice and that they are sufficiently demonstrated as BACT for the combined-cycle CT in this application.

3.1(5.4) BACT for CT VOC

The Project will be subject to BACT for VOC. It will be shown that BACT control technology for VOCs on the CT with HRSG is identical to that for CO but with different emission limitations.

5.4.1 Minimum VOC Regulatory Requirements

There are no applicable NSPS, NESHAPs or North Carolina SIP requirements applicable to VOC emissions from combined-cycle CTs.

5.4.2 Identification of Available VOC Control Technologies (Step 1)

VOC emissions are formed in CTs as a result of incomplete combustion of carbonaceous fuels. Similar to the generation of CO emissions, the primary factors influencing the generation of VOC emissions are temperature and residence time within the combustion zone. Providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion can minimize VOC emissions. However, these combustion techniques can sometimes increase NOx emissions. Therefore, a compromise must be reached whereby the flame temperature reduction is set to achieve the lowest NOx emission rate possible while maintaining VOC emission rates at acceptable levels.

There are two basic techniques for controlling VOC emissions from combustion units: good combustion practices and post-combustion controls – installation of oxidation catalysts in the HRSG to oxidize VOC to CO2. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, oxidation catalysts have been applied extensively over the last 10 years, primarily for CO control, but also for VOC control.

5.4.2.1 Combustion Controls

VOC emissions are generated from the incomplete combustion of carbon in the fuel and organic compounds. Optimization of the combustion chamber designs and operation to improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering VOC emissions. This process is often referred to as combustion controls. Combustion controls in large CTs generally utilize “lean combustion” (large amount of excess air) to produce a cooler flame temperature to minimize NOx formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion, thus minimizing VOC emissions.

5.4.2.2 Oxidation Catalysts

Oxidation catalysts are a proven post-combustion control technology widely in use on large CTs to abate VOC emissions. An oxidation catalyst oxidizes the VOC in the exhaust gases to form CO2. No supplementary reactant is necessary in conjunction with the catalyst for the oxidation reaction to proceed. This technology is referenced in section 5.3.2.2. above and explained fully in the application.

Oxidation catalysts have been employed successfully for two decades on natural gas-fired CTs. An oxidation catalyst is considered to be technically feasible for application to this Project.

5.4.2.3 EMx™

The EMx™ system previously described in Section 5.2.2.6 also controls CO and VOC. The EMx™ system employs a single catalyst to simultaneously oxidize CO and VOC to CO2 and NO to NO2.

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5.4.3 Elimination of Technically Infeasible Options (Step 2)

The technical feasibility of the identified available CT VOC control options is summarized as follows:

- **Combustion controls.** Combustion controls have been demonstrated successfully in numerous applications and is considered technically feasible for the proposed Project’s combined-cycle CT.
- **Oxidation Catalysts.** Catalytic oxidation has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed Project’s combined-cycle CT.
- **EMx™.** As previously discussed in Section 5.2.4, the EMx™ control technology is not considered available (and therefore is considered technically infeasible) because it has not been commercially demonstrated on large combined-cycle CT units.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Combustion controls; and
- Oxidation catalysts.

5.4.4 Ranking of Remaining Control Technologies (Step 3)
Combustion controls and catalytic oxidation are compatible technologies and considered together, represent the best control strategy for VOC emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.4.5 Evaluation of Most Effective Controls (Step 4)
Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy, and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for VOC.

5.4.6 Selection of BACT and Determination of VOC Emission Limits (Step 5)
NTE proposes a combination of exclusive natural gas use, combustion controls, and oxidation catalysts to meet BACT requirements for VOC. These technologies, when considered together, represent the most stringent VOC controls available for combined-cycle CTs. The proposed VOC emission limits are summarized below for normal operating loads between 50 and 100 percent. NTE proposes to meet the VOC limit on a 3-hour average basis (stack test). (A discussion of alternative limits during startup and shutdown events is provided in Section 5.9).

<u>MHPSA M501GAC (50 – 100 Percent Load)</u>:

VOC	1.0 ppmvd @ 15 percent O_2 for all operating loads between 50 and 100 percent, w/out duct firing
	1.5 ppmvd @ 15 percent O2 for all operating loads between 50 and 100 percent, w/ duct firing

Based on a review of LAER and BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, the majority of recent VOC BACT determinations include combustion controls and oxidation catalysts. The most stringent recent limits on projects that are in operation are approximately 1.0 ppmvd @ 15 percent O2 for VOC without duct firing. Summaries of BACT determinations for VOC emissions from combined-cycle CTs permitted since January 2004 are presented in Appendix D, Table D-3. A review of VOC permit limits indicates that 12 have VOC limits at the 1 ppmvd @ 15 percent O2 level without duct firing. The limits with duct firing for those facilities are typically in the range of 1.5 to 3.9 ppm @ 15% O2. In addition, three projects (Brunswick Power, Dominion Warren and Chouteau Power Plant 2) have VOC limits that are more stringent: The permitted VOC limits, corrected to 15 percent O2 are 0.7 ppm, 3-hour average, for Brunswick and Warren (without duct firing; 1.6 ppm with duct firing) and 0.3 ppm, 3-hour average, for Chouteau. The Brunswick and Warren projects are currently under construction and Chouteau 2 is in the initial phases of operations as of the summer of 2011. As such, a VOC limit less than 1.0 ppmvd @ 15 percent O2 (without duct firing) on a 3-hour averaging basis is not yet considered demonstrated in practice, due to insufficient operating history at that level. Applicable VOC emission limits with duct firing cannot typically be compared on an equivalent basis because the VOC emissions input from duct firing will vary as a function of the duct burner heat input rate. For example, combined-cycle units with relatively large duct burner heat input relative to the CT will have higher uncontrolled VOC emissions and therefore, higher controlled emissions after the oxidation catalysts. The oxidation catalysts are much less effective at VOC control than CO control (typically 30 percent VOC control compared to 80+% CO control). Therefore, the 1.0 ppmvd @ 15 percent O2 limit without duct firing and 1.5 ppm @ 15% O2 with duct firing, based on a 3-hour averaging time (average of three 1-hour stack test runs) is considered the most stringent VOC limit achieved in practice for the proposed combined-cycle units.

The DAQ agrees that the proposed VOC emissions limits are equivalent to the most stringent identified limits that are considered achieved in practice and they are sufficiently demonstrated as BACT for the combined-cycle CT in this application.

3.1(5.5) BACT for CT H_2SO_4

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. While the SO_2 generally remains in a gaseous phase throughout the flue gas flow path, a small portion may be oxidized to SO_3. The SO_3 can subsequently combine with water vapor to form H_2SO_4. The Project's SO_2 emissions are below the PSD significance threshold and thus the PSD BACT requirements do not apply to SO_2 (see Section 4.3 of the application). Potential H_2SO_4 emissions from the Project are estimated to exceed the PSD significance threshold and, therefore, are subject to BACT. Note that the following discussion however does include SO_2 since it is a precursor.

5.5.1 Minimum SO2 and Sulfuric Acid Regulatory Requirements

The NSPS (Subpart KKKK) limits applicable to SO_2 emissions from natural gas-fired combined-cycle CTs are as follows:

- 0.9 lb/MWh gross output or
- 0.06 lb SO_2/MMBtu heat input.

15A NCAC 02D .0516 limits SO_2 emissions from any combustion unit to 2.3 lb/MMBtu of heat input.

The Project will comply with the applicable standards for SO_2 by combusting pipeline quality natural gas. Using 0.7 grains sulfur/100 ft3 sulfur content and approximately 1,023 Btu/ft3 (HHV) heat content for natural gas, the SO_2 emission rate for is estimated as 0.002 lb/MMBtu.

5.5.2 Identification of Available SO2 and Sulfuric Acid Control Technologies (Step 1)

Technologies generally employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and post-combustion add-on controls that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas [also referred to as flue gas desulfurization (FGD) systems]. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, post-combustion controls have not been applied to CTs. Minimization of SO_2 emissions has been achieved in practice through combustion of natural gas and ULSD backup fuel.

5.5.2.1 Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to the end user. The fuel proposed for the Project combined-cycle units is natural gas only. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline. The sulfur content of pipeline quality natural gas is typically 2.0 grains per 100 SCF or less. Based on specifications obtained from the gas supplier, NTE is proposing a natural gas sulfur limit of 0.7 grains/100 SCF.

5.5.2.2 Flue Gas Desulfurization (FGD)

FGD systems are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts the SO_2 to sulfite or sulfate salts. FGD systems applied in practice to coal- and some oil-fired power plants (external combustion boilers) include wet scrubbers and dry scrubbers, such as spray dryer absorbers. FGD has not been applied to CTs.

5.5.3 Elimination of Technically Infeasible Options (Step 2)

The technical feasibility of the identified available CT SO_2 and sulfuric acid mist control options is summarized as follows:

- **Fuel Treatment.** The sulfur content in pipeline quality natural gas, which is treated by the fuel supplier prior to distribution, is already very low, and additional fuel treatment by the end user is considered technically infeasible.
- **FGD.** The removal efficiency of an FGD system decreases with decreasing inlet SO_2 concentration. FGD technology has been shown to function efficiently on emissions streams with relatively high uncontrolled sulfur levels (for example, for boilers firing high-sulfur coal). However, the SO_2 emissions from the proposed CT are two orders of magnitude lower than emission rates typically achievable using flue gas desulfurization. Moreover, there have been no applications of FGD technology to natural gas-fired combined-cycle units. This is consistent with the EPA RBLC database summary presented in Appendix D, Table D-5 of the application. As a result, the FGD technology is not considered to be technically feasible for combined-cycle CTs.

Based on the preceding discussion, the only technically-feasible option for SO_2 and H_2SO_4 carried forward for further analysis is fuel treatment/combustion of pipeline quality natural gas.

5.5.4 Ranking of Remaining Control Technologies (Step 3)

The use of pipeline quality natural gas is the only available and, therefore, top level of control for SO_2 and sulfuric acid mist. Therefore, a ranking is not required to establish the top technology.

5.5.5 Evaluation of Most Effective Controls (Step 4)

Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for SO2 and sulfuric acid mist. Regardless, there are no potential energy, environmental, or economic impacts that would preclude the use of pipeline quality natural gas in the combined-cycle CT.

5.5.6 Selection of BACT and Determination of H2SO4 Mist Emission Limits (Step 5)

NTE proposes exclusive use of natural gas in the CT and DB to minimize emissions of SO2 and H2SO4 mist, which represents the most stringent SO2/H2SO4 controls available for combined-cycle CTs. The proposed SO2 and H2SO4 mist emission limits are summarized below, applicable to all operating loads. NTE proposes to meet the limits based on fuel sulfur monitoring/fuel supplier certifications.

Sulfur content in natural gas	0.7 grains/100 SCF (enforceable through fuel supplier certifications/monitoring records)
H_2SO_4 Mist	0.0015 lb/MMBtu (calculated based on fuel sulfur content limit and based on MHPSA's engineering estimates regarding the conversion of SO_2 to SO_3 in the CT and DB, further conversion from SO_2 to SO_3 by the oxidation catalysts and assumed 100% conversion of SO_3 to H_2SO_4).

Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired power plants. The practical limitation is considered region-specific, depending on the source/specifications of the natural gas in the pipeline supplying the plant. Based on a review of BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, as summarized in Appendix D, Tables D-5 and D-6, limits have been provided either for sulfur content or lb/MMBtu. Recent sulfur contents range from 0.1 to 2 grains/100 SCF and SO2 emission factors range from 0.0003 to 0.0057 lb/MMBtu. For the proposed Project, Williams/Transco Pipeline gas tariff specifications indicate a pipeline sulfur content limit of 20 grains/100 SCF for total sulfur (including the sulfur in any hydrogen sulfide and mercaptans). In addition, review of several months of daily monitoring data from the nearest monitoring station (Gage Road) provided by Transco indicates significantly lower actual sulfur contents in the pipeline in the vicinity of the Project (maximum of about 0.52 grains/100 SCF). However, Transco cautions that the historical monitoring data may not be reliable to predict future conditions (sulfur content may be higher) as the pipeline system begins flowing north to south, rather than south to north under existing conditions. Due to this uncertainty, the Project is proposing a sulfur content limit of 0.7 grains/100 SCF. More stringent listed SO2 and H2SO4 mist emission limits in the RBLC are specific to projects with more stringent natural gas sulfur content specifications that are applicable to the geographic location of those projects. As SO2 and H2SO4 mist formation are directly related to fuel sulfur content, the applicable emissions limitations must also be directly linked to those specifications.

The DAQ agrees with the proposed H2SO4 mist emissions limits are equivalent to the most stringent identified limits that are considered achieved in practice, given the maximum expected natural gas sulfur content, and that it is sufficiently demonstrated as BACT for the combined-cycle CT in this application.

3.1(5.6) BACT for CT Particulate Matter (PM10/PM2.5)

Emissions of particulate matter (PM) from combustion occur as a result of inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles, and mineral matter in water that may be injected for NOx control during diesel firing (not relevant for the Project, which is based on exclusive natural gas combustion). PM is also theorized to come from dust particles in the ambient air drawn into the turbine's compressor, which then "pass through" and exit the stack. Although this re-entrained PM is not due to operation of the CT itself, it may be detected by the methods used for stack testing. The Project will utilize high-efficiency inlet air filters to avoid drawing particulates through the CT and out the stack.

PM emissions can also result from the formation of ammonium salts (sulfates and nitrates) due to the conversion of SO2 to SO3, which is then available to react with ammonia to form ammonium sulfate and NOx, which may also react with ammonia to form ammonium nitrate salts. Ammonium salts are very fine particulate, typically in the sub-micron size range. In addition, as PM10 and PM2.5 include both filterable and condensable fractions (front-half and back-half), condensable organics may also be measured as particulates. All of the PM emitted from the CT is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM10 and PM2.5 emission rates are assumed to be the same.

The Project's PM, PM10 and PM2.5 emissions are greater than the respective PSD significance thresholds and thus the PSD BACT requirements apply to PM, PM10 and PM2.5 (see Section 4.3 of the application).

5.6.1 Minimum PM10/PM2.5 Regulatory Requirements

Under 15A NCAC 02D .0503(c), the PM emission limitation is no more than 0.19 lb/MMBtu heat input. The Project's CT will be subject to this limitation. However, the Project will comply with the applicable standard by combusting pipeline quality natural gas (0.7 grains/100 SCR), which is estimated to result in a total PM emission rate less than 0.006 lb/MMBtu.

5.6.2 Identification of Available PM10/PM2.5 Control Technologies (Step 1)

No add-on control technologies are listed in the RBLC listings for CTs. Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content are the only control methods identified for CTs. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. In addition, high-efficiency CT air inlet filters are typically specified to minimize PM being drawn in with CT air.

Add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial CTs; however, they are considered available technologies, since they can be obtained through commercial channels. The feasibility of add-on controls is further evaluated in Section 5.6.3.

Controls identified as available for minimizing PM10/PM2.5 emissions from CTs are:

- Combustion control;
- Negligible or no-ash fuels (use of pipeline quality natural gas);
- Low sulfur fuels (use of pipeline quality natural gas); and
- High-efficiency CT air inlet filters.
- ESPs and baghouses

5.6.3 Elimination of Technically Infeasible Options (Step 2)

Although considered available controls, ESPs and baghouses, have not been and cannot be installed and successfully operated on combustion turbine exhausts to achieve reductions in PM10/PM2.5 emissions and, therefore, are not considered applicable or technically feasible. They are not applicable or technically feasible for CT applications for the following reasons:

1. The uncontrolled PM10/PM2.5 concentrations in the CT/HRSG exhaust are lower than the best level of control that ESPs and baghouses can achieve. e.g., the filterable PM10/PM2.5 in the CT/HRSG exhaust, based on MHPSA performance data/guarantee is <0.0041 lb/MMBtu or:

   11.5 lb/hr / (60 min/hr) x (7000 grains/lb) / (1,008,285 dscf/min) = 0.0013 grains/dscf

2. The best performing ESPs and baghouses are capable of achieving a controlled filterable PM10/PM2.5 emission rate in the range of 0.01 to 0.02 lb/MMBtu or in the range of approximately 0.005 to 0.01 grains/dscf.

3. ESPs or baghouses would have no effect on the condensable fraction of the PM.

As add-on PM10/PM2.5 controls are considered technically infeasible for combustion turbines, no further evaluation of the economic or energy impacts of those controls are required for the top-down BACT analysis. Each of the remaining available CT PM control options identified in Section 5.6.2 are considered technically feasible.

5.6.4 Ranking of Remaining Control Technologies (Step 3)

Exclusive natural gas use, high-efficiency CT air inlet filters and DLN combustors are compatible technologies and considered together, represent the best control strategy for PM10/PM2.5 emissions from large combined-cycle CTs. Therefore, a ranking is not required to establish the top technology.

5.6.5 Evaluation of Most Effective Controls (Step 4)

Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for PM10/PM2.5. Regardless, there are no potential energy, environmental, or economic impacts that would preclude the use of pipeline quality natural gas, high-efficiency air inlet filters and DLN in the combined-cycle CTs.

5.6.6 Selection of BACT and Determination of PM10/PM2.5 Emission Limits (Step 5)

NTE proposes exclusive use of natural gas in the CT and DB, high-efficiency air inlet filters and DLN combustors to minimize emissions of PM10/PM2.5, which represents the most stringent controls available for combined-cycle CTs. The proposed PM10/PM2.5 emission limits are summarized below, applicable to all operating loads. NTE proposes to meet the limits based on fuel sulfur monitoring/fuel supplier certifications and initial stack testing, if necessary.

Sulfur content in natural gas	0.7 grains/100 SCF (enforceable through fuel supplier certifications/monitoring records)
$PM/PM_{10}/PM_{2.5}$ (total filterables + condensables)	0.0041 lb/MMBtu, CT only 0.0059 lb/MMBtu, CT + DB (Estimated based on fuel sulfur content limit, SO_3 formation and conversion to ammonium sulfates and nitrates, with addition of organic condensables). If necessary, initial stack testing would be performed using EPA Reference Methods 201 or 201A for filterable PM and Method 202 (revised 12/10/11 for condensable PM).

Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired power plants. The practical limitation is considered region-specific, depending on the source/specifications of the natural gas in the pipeline supplying the plant. Based on a review of BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, as summarized in Appendix D, Table D-4, limits have been provided either for sulfur content or lb/MMBtu of PM10/PM2.5. Recent sulfur contents range from 0.1 to 2 grains/100 SCF and PM10/PM2.5 emission factors range from 0.0025 to 0.019 lb/MMBtu. For the Project, monitored sulfur concentrations over several recent months in the nearest Transco monitoring station to the Project Site indicate a maximum of 0.52 grains/100 SCF. However, to allow for future variations and the very likely scenario of the pipeline gas flow reversing direction to flow from the north, the Project is proposing a sulfur content limit of 0.7 grains/100 SCF. More stringent listed PM10/PM2.5 emission limits in the RBLC are generally specific to projects with more stringent natural gas sulfur content specifications that are applicable to the geographic location of those projects. As PM10/PM2.5 emissions are directly affected by fuel sulfur content, the applicable emissions limitations must also be linked to those specifications.

The DAQ agrees that the proposed PM10/PM2.5 emissions limits are reasonable considering the goals of BACT which takes "*into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*"

3.1(5.7) BACT for CT Greenhouse Gases (GHG)

The Project CT and DB will be fired exclusively with natural gas, which will emit three GHGs: methane (CH4), CO2, and nitrous oxide (N2O). CH4 is emitted from combustion devices burning natural gas as a result of incomplete combustion. Although CH4 emissions can be reduced by operating the combustion devices at higher flame temperatures, higher excess oxygen levels, and increased residence time, these techniques for reducing CH4 emissions can increase NOx emissions. Consequently, achieving low CH4 and NOx emission rates is a balancing act in the combustor design and operation. CO2 will be emitted from the combined-cycle CT because it is a combustion product of any carbon-containing fuel. However, relative to many other types of fossil fuel-fired power plants, natural gas combustion produces exhaust streams that are dilute in CO2 concentration. Thus, as discussed in more detail below, full capture of CO2 emissions from this plant is inefficient, challenging, and costly. N2O will be emitted from the combined-cycle CT in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process and due to catalytic reduction reactions in the SCR systems used for NOx control.

It is worth noting that for the CT the PTE of CH4 and N2O as CO2e combined is less than 1% of the total GHGs. Although the application addresses BACT for these GHGs, this review document will focus on the direct CO2 emissions.

5.7.1 Minimum GHG Regulatory Limits

There are no currently-applicable NSPS or state rules that would establish a baseline GHG emission rate for the combined-cycle CT at the Project.

5.7.2 Identification of GHG Control Technologies (Step 1)

CH4

The potentially available control technologies for CH4 emissions are Good Combustion Practices, EMx™ and Oxidation Catalysts and are addressed in the application.

N2O

The only identified control technologies for the control of N2O from combined-cycle CTs are aggressive energy-efficient design, in order to minimize the amount of fuel combusted, and elimination of SCR.

CO2

The potentially available control technologies for CO2 emissions from combined-cycle CTs fired with natural gas are:

- Energy-efficient design in order to minimize the amount of fuel combusted;
- Use of low-carbon fuels in order to minimize the formation of CO2 from fuel combustion; and
- Carbon capture and storage (CCS).

5.7.2.1 Good Combustion Practices (CH4)

Good combustion practices for combined-cycle CT fired with natural gas to reduce methane emissions are fully described in the permit application.

5.7.2.2 Oxidation Catalyst (CH4)

As discussed in Section 5.3.2.2, oxidation catalysts have been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle CTs and would also provide reduction in CH4 emissions. The rationale for its consideration as a BACT technology is explained in the permit application.

5.7.2.3 EMx™ (CH4)

EMx™ was evaluated as part of the NOx and CO/VOC BACT analyses for the CT in Sections 5.2 and 5.3 and was eliminated as technically infeasible for the class of CT proposed for the Project. No further evaluation of EMx™ is presented here for the GHG BACT analysis.

5.7.2.4 Low-Carbon Fuel
Table 5-3 presents the amount of CO2 formed when combusting fossil fuels, including natural gas.

Table 5-3 – CO_2 Emission Factors for Fossil Fuels

Fuel	Pounds CO_2 per MM/Btu[(1)]
Coal	225
Residual Oil	210
Diesel	161
Natural Gas	117

(1) Energy Information Administration at http://www.eia.doe.gov/oiaf/1605/coefficients.html

As shown in this table, use of natural gas reduces the production of CO2 during the combustion process relative to burning solid and liquid fossil fuels.

5.7.2.5 Energy Efficient Design
A highly-efficient combined-cycle power plant reduces the amount of fuel used to produce the heat and electrical power. This reduction in fuel corresponds directly to the amount of GHG produced. Elements of a highly energy-efficient design for the combined-cycle power plant will include continuous excess air monitoring and control. Excessive amounts of combustion air in HRSG results in energy inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. This requires the installation of an oxygen monitor in the stack and damper controls on the combustion air dampers. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only GHG emissions but also NOx emissions. The combined-cycle CT at the Project will be equipped with oxygen monitors as part of the continuous emission monitoring system.

5.7.2.6 Carbon Capture and Storage (CCS)
CCS can be used to reduce atmospheric emissions of CO2 after formation. However, the inherent design of the combined-cycle CT at the Project will produce relatively dilute CO2 streams, such that separation of CO2 from other exhaust gas constituents (i.e., "capture") is too difficult and costly to be practical. CSS is discussed further in the application.

5.7.3 Elimination of Technical Infeasible Options (Step 2)
The technical feasibility of the identified available CT GHG control options is summarized as follows:

Good Combustion Practices. Good combustion practices, as described herein, are technically feasible and are inherent in the design of the proposed Project's combined-cycle CT.

Oxidation Catalysts. Catalytic oxidation has been demonstrated successfully in numerous applications and is already included in the proposed Project's combined-cycle CT for CO and VOC control.

EMx^{TM}. As previously discussed in Section 5.2.3, the EMxTM control technology is not considered available (and therefore is considered technically infeasible) since it has not been commercially demonstrated on large combined-cycle CT units.

Low-Carbon Fuels. The combined-cycle CT will be exclusively fueled with low-carbon natural gas. There are no control options involving the use of low-carbon fuels in these units that represent technically-feasible options for reducing GHG emissions relative to the proposed fuel.

Energy Efficiency. Each of the identified strategies for energy-efficient design is technically feasible and is inherent in the design of the combined-cycle CT.

Carbon Capture and Storage. The pre-combustion technique for CO2 separation involves substituting pure oxygen for air in the combustion process. This "oxyfuel" process has not yet been tested or demonstrated in a large scale facility. Accordingly, CCS involving pre-combustion CO2 separation and capture is not technically feasible for the combined-cycle CT at the Project. With regard to post-combustion CO2 capture, there are a number of evolving methods and processes that could be used to capture CO2 from dilute exhaust gases produced by the combined-cycle CT. For example, capture using physical or chemical absorption techniques with subsequent compression, transport and storage of the recovered CO2 are assumed for the purposes of this analysis to be technically feasible. Although a strong case can be made that CCS is not technically feasible for gas-fired power plants (including the fact that EPA found CCS not to be adequately demonstrated in its proposal of the GHG NSPS) the technology was voluntarily carried forward in this analysis, in order to evaluate the cost impacts.

Eliminating SCR. Elimination of SCR from the design of the combined-cycle CT at the Project is technically feasible and would be expected to result in lower N2O emission rates.

Based on the preceding discussion, the following technologies are considered technically feasible and are carried forward for further analysis:

- Good combustion practices;
- Oxidation catalysts.
- Low-carbon fuel;
- Energy efficiency;
- Post-combustion CCS; and
- Eliminating SCR.

5.7.4 Ranking of Remaining Controls (Step 3)
The use of good combustion practices, oxidation catalyst, low-carbon fuels, and energy-efficient design to reduce GHG emissions from combined-cycle CT is inherent in the design of the proposed Project. The combination of these controls is considered the baseline condition. The only technically feasible strategies for further controlling GHG emissions from the combined-cycle CT are CCS, for reductions in CO2 emissions, and elimination of SCR, for reductions in N2O emissions.

5.7.5 Evaluation of Most Effective Controls (Step 4)

5.7.5.1 Elimination of SCR
Use of SCR to achieve controlled NOx emissions of 2.0 ppmvd @ 15 percent O2 is proposed as BACT for the Project's combined-cycle CT. Elimination of the SCRs would result in an increase in allowable NOx emissions of approximately 1,034 tons per year (based on 90 percent NOX reduction in the SCRs) from the CT. This increase significantly outweighs the reduction in N2O emissions that could be achieved by eliminating the SCRs and would likely result in violations of the NO2 NAAQS. The Project considers this to be an unacceptable, adverse environmental impact. Elimination of SCR, therefore, does not represent BACT for GHG emissions.

5.7.5.2 Carbon Capture and Storage
The permit application thoroughly details how the results of cost, energy and environmental impact analysis for the proposed CT were determined as summarized in Table 5-4 and reproduced here. These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the combined-cycle CTs at the proposed Project.

5.7.6 Selection of BACT for CT GHG (Step 5)
Based on the GHG BACT analysis, the following technologies are proposed as BACT for the Project:

- Good combustion practices;
- Oxidation catalysts.
- Low-carbon fuel; and
- Energy efficiency/combined-cycle power plant

The Project is proposing the following GHG BACT limitations:

The M501GAC CT will have heat rate, at ISO conditions with no duct firing:

- new and clean (initial test), not to exceed the following limit of 6,942 Btu/kW-hr, HHV (gross)
- life of the facility, not to exceed the following limit of 7,335 Btu/kW-hr, HHV (gross)

The total GHG on a CO2e basis from the combined-cycle CT unit with duct firing will not exceed the following limit of 1,676,538 TPY

The totals include a 5 percent factor to account for thermal efficiency degradation between major inspection/maintenance intervals. A CO2 CEMS or approved alternate method as specified under 40 CFR 75 will be used to demonstrate compliance with this combined limit. The N2O and CH4 components of CO2e will be calculated by monitoring fuel use and using fuel-specific emission factors (e.g., AP42 Table 3.1-2a) or site-specific factors determined through initial stack testing.

Table 5-4 – Summary of CCS Cost, Energy and Environmental Impacts Analysis

M501GAC:

Parameter	Units	Factor[1]	Assumed or Calculated Value	Units	Notes
Plant Size	MW		519	MW	
Emission rate w/out capture	kg CO2/MWh	362	1,581,982	tons/yr	from Table C-13
Percent Reduction	%	86	86	%	
Emission rate w/ capture	kg CO2/MWh	52	221,477	tons/yr	14% not captured
CO2 captured			1,360,504	tons/yr	86% captured
Capture energy requirement	% MWh	16	83.0	MW	
Nat. gas use for incremental MW			7,068	Btu/kWh (HHV)	@ 59 deg. F (annual avg.), 100% load
			4,989	MM SCF/yr	
Incremental CO2 w/ capture			117	lb CO2/MMBtu	from Table C-2, CT vendor data
			291,784	tons/yr	
Total capital w/out capture	US$/kW	568	$ 381	$Million	Factor scaled from 2002 (CPI 180) to 2014 dollars (CPI 233).
Total capital w/ capture[2]	US$/kW	998	$ 670	$Million	Factor scaled from 2002 (CPI 180) to 2014 dollars (CPI 233).
CO2 pipeline capital cost[3]			$ 361	$Million	
Total capital w/ capture and pipeline			$ 1,031	$Million	
Incremental capital			$ 650	$Million	
Annualized incremental capital			$ 97	$Million	15% of capital costs
Annualized natural gas costs			$ 26	$Million	$5 per MMBtu for NG[4]
Annual O&M costs			$ 34	$Million	5% of total capital
Total annual costs			$ 157	$Million	
Cost of CO2 captured			$ 99	$/ton	
Environmental Impacts (Increased Emissions)					
Pollutant	**Units**	**Factor**	**Calculated Value**	**Units**	**Notes**
NOx	lb/MMBtu	0.0078	20.0	tons/yr	@ 59 deg. F (annual avg.), 100% load
CO	lb/MMBtu	0.0047	12.1	tons/yr	@ 59 deg. F (annual avg.), 100% load
VOC	lb/MMBtu	0.0020	5.2	tons/yr	@ 59 deg. F (annual avg.), 100% load
SO2	lb/MMBtu	0.0020	5.1	tons/yr	@ 59 deg. F (annual avg.), 100% load
PM10/PM2.5	lb/MMBtu	0.0029	7.3	tons/yr	@ 59 deg. F (annual avg.), 100% load

1. Representative values listed in IPCC Special Report on Carbon Dioxide Capture and Storage, Chapter 3: Capture of CO2, Table 3.15, (http://www.ipcc.ch/pdf/special-reports/srccs/srccs_chapter3.pdf)
2. Costs include CO2 compression, but not additional CO2 transport and storage costs.
3. See CO2 Pipeline Cost estimate that follows.
4. Based on the 5 year average for North Carolina, based on EIA data (http://www.eia.gov/dnav/ng/hist/n3045nc3a.htm)

Consistent with other recent permits for similar facilities based on review of GHG BACT determinations summarized in Appendix D, Table D-7 of the application, the proposed gross heat rate limits incorporate reasonable compliance margins for purposes of establishing a permit condition that can be practically enforced and based on the vendor performance data provided in the application.

As summarized in Table C-18 of the application, the gross design heat rates were first adjusted to account for the difference between the vendor guarantee point and the estimated performance data. Next, the resulting adjusted gross heat rates were further adjusted for measurement accuracy and degradation margins in a similar manner used to derive heat rate permit conditions for other recent determinations to ensure that the numerical heat rate permit limit reflects a reasonable margin of compliance. Specifically, NTE's margins included the following:

- A reasonable design margin of 5 percent to reflect that the equipment as actually constructed and installed may not fully achieve the assumptions that went into the vendor design calculations;
- An additional 1 percent margin allowing for the accuracy and test tolerances of the testing equipment used to measure and calculate heat rate; and
- A reasonable performance degradation margin of 6 percent to reflect reduced efficiency from normal wear and tear on the equipment between major maintenance overhauls.

The total compliance margin, based on these adjustments, is 12 percent, which is generally consistent with the assumptions used to develop enforceable heat rates for other recent combined-cycle power plant permits.

A summary of recent GHG BACT determinations for combined-cycle power plants obtained from the RBLC and from review of other permits not in the RBLC is provided in Appendix D, Table D-7 of the application. Direct comparison of NTE's proposed BACT limits is complicated by differences in the bases used to establish GHG BACT limits. For example, some of the heat rate (Btu/kW-hr) and output-based limits (lb CO2/MW-hr) limits are provided on a gross basis and others are provided on a net basis. Furthermore, design performance and degradation factors that are used to adjust the base heat rates that are based on vendor design data to realistic long-term values vary from permit to permit. From review of available permit applications and documentation on BACT determinations, the total allowances for these factors generally varies between about 8 and 14 percent. The differences in the units and basis of limits make it difficult to directly compare BACT determinations.

NTE's proposed adjusted heat rates are compared to the following recent permit limits for other similar projects where the limits are on a similar basis, all on a gross electrical output, HHV fuel, ISO conditions, without duct firing for comparison purposes:

Project	Gross Heat Rate, ISO, No Duct-Firing (Btu/kW-hr) HHV*
NTE M501GAC	7,335
Footprint Power Salem Harbor GE 107F Series 5	7,247
Green Energy Partners/Stonewall GE 7FA.05 or Siemens SGT6-5000F	7,340
Moxie Patriot Siemens SGT6-8000H or Mitsubishi M501GAC	7,459
Moxie Liberty Siemens SGT6-8000H or Mitsubishi M501GAC	7,459
Garrison Energy Center GE 7FA	7,717
St Joseph Energy Center – GE or Siemens F Class	7,646
Cricket Valley GE 7FA	7,605
Russell City Siemens/Westinghouse 501F	7,730
*Listed values represent adjusted heat rates, including all margins allowing for design, performance and CT degradation factors.	

It also should be noted that the proposed BACT limits for CO2 emissions from the CT would comply with EPA's proposed NSPS for GHG emissions of 1,000 lb/MW-hr of gross output applicable to CT power plants on a 12-month rolling average basis. The estimated equivalent CO2 emissions rates are 825 and 872 lb/MW-hr (gross), respectively for the M501GAC CT new and clean and life of facility conditions (see Table C-18 in the application).

The DAQ agrees that the proposed GHG BACT limitations are reasonable considering the goals of BACT which takes “*into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.”*

3.1(5.8) BACT for CT Ammonia (NH3) Slip Emissions

NH3 is not a regulated air pollutant under the federal PSD program. However, as a potential PM2.5 precursor pollutant, BACT for NH3 is addressed in this section. NH3 emissions from the combined-cycle CTs are an unavoidable consequence of the injection of NH3 for NOx emissions control using SCR systems. In order to achieve as high NOx emissions conversion efficiency as possible, it is necessary to inject more moles of NH3 than are required to stoichiometrically react with the moles of NOx. The excess NH3 (or NH3 "slip") will pass through the SCR system and will be vented to the atmosphere. In addition, even for a system designed to achieve at least 90 percent NOx emissions reduction, as will be the case for the Project, as much as 10 percent of the corresponding moles of NH3 will not react with NOx and will also pass through the SCR system and will be vented to the atmosphere.

5.8.1 Minimum NH3 Regulatory Requirements

There are no NSPS (Subpart KKKK) or state regulatory limits applicable to NH3 emissions from natural gas-fired combined-cycle CTs.

5.8.2 Identification of Available NH3 Control Technologies (Step 1)

No add-on control technologies are listed in the RBLC listings for CTs and none have been identified from review of other permits or research. NH3 slip emissions can be minimized from SCR-controlled CTs through effective process controls to optimize the NH3 injection rate and maximize the efficiency of reactions in the SCR. Examples of process optimization include refinement of the injection grid distribution pattern, additional injection nozzles and use of a feed-forward process control loop that would include both inlet and outlet NOx emissions continuous emissions monitoring systems (CEMS). The goal of such process changes is to provide more precise control of the distribution of NH3 to the SCR catalyst than is provided by more conventional injection systems. Additional catalyst volume may also be necessary to maximize the NOx reduction reaction efficiency (i.e., reduce the amount of unreacted NH3), which would also reduce NH3 slip. However, an increase in catalyst volume would need to be balanced with the corresponding increase in gas-side back pressure and the reduction in CT generating efficiency. For example, and approximate 10 percent increase in catalyst volume is estimated to increase pressure drop in the SCR by approximately 30 to 40 percent, depending on the SCR supplier.

The Project's commitment to exclusively use natural gas in the CT will also reduce potential NH3 emissions as the higher NH3 injection rates necessary for fuel oil operating scenarios in CTs would result in higher NH3 slip emissions.

5.8.3 Elimination of Technically Infeasible Options (Step 2)

Each of the available CT NH3 control options identified in Section 5.8.2 is considered technically feasible:

- Exclusive natural gas combustion;
- NH3 injection system process optimization and
- Increased SCR reactor/catalyst volume.

Add-on controls, such as wet scrubbers, have never been applied to commercial CTs are not considered technically infeasible.

5.8.4 Ranking of Remaining Control Technologies (Step 3)

The Project is proposing to use NH3 injection process optimization in combination with exclusive natural gas use. In addition, Project engineers, EPC contractors and CT vendors will work with potential SCR vendors and catalyst suppliers to optimize the SCR catalyst volume to maximize the SCR reaction and minimize NH3 slip, while adhering to the CT vendors' back pressure constraints. This design optimization is critical so that plant generating efficiency is not impacted. This combination of technologies represents the best control strategy for NH3 emissions from large combined-cycle CTs. Therefore, further ranking is not required to establish the top technology.

5.8.5 Evaluation of Most Effective Controls (Step 4)
Based on EPA "top-down" BACT analysis guidance, analyses of economic, energy and environmental impacts is not required in this case as the "top" or most stringent control technology is selected for NH3. Regardless, there are no potential energy, environmental, or economic impacts that would preclude the use of pipeline quality natural gas, NH3 injection system optimization and SCR catalyst volume optimization in the combined-cycle CTs. One caveat is that even a small increase in catalyst volume resulting in increased pressure drop would result in collateral environmental impacts due to increased fuel consumption in the CTs, which would increase emissions of all regulated pollutants, including GHGs.

5.8.6 Selection of BACT and Determination of NH3 Emission Limits (Step 5)
NTE proposes exclusive use of natural gas in the CT and DB, NH3 injection system process optimization and SCR catalyst volume optimization to minimize NH3 slip emissions, which represents the most stringent NH3 controls available for combined-cycle CTs. The proposed NH3 emission limit for the CT is 5 ppmvd @ 15 percent O2, applicable to all normal operating loads (above 50 percent). NTE proposes to meet the limits based on CEMS with a 1-hour averaging time.

Based on a review of BACT determinations in EPA's RBLC and permits for CTs not included in the RBLC, as summarized in Appendix D, Table D-1 of the application, the most stringent NH3 slip limits, where listed, are generally 5 ppmvd @ 15 percent O2. There are several final determinations since 2004 (Kleen Energy, Dominion Warren, Footprint Salem, Pioneer Valley and Brockton) with a lower NH3 emission limits. Kleen and Warren are limited to 2 ppmvd @ 15 percent O2 for steady state operations and 5 ppmvd @ 15 percent O2 for transient (startup and shutdown) operations.

The three Massachusetts permits (Footprint, Pioneer Valley and Brockton), which have not been constructed, are limited to 2 ppmvd @ 15% O2 for all steady-state conditions. Dominion Warren is currently under construction. Its permit also specifies that compliance with the NH3 slip limit must be demonstrated at least 95 percent of the time the SCR is operating, based on a 30-day rolling period.

The Kleen Energy facility is the only facility with an NH3 limit less than 5 ppm that is operating, since the summer of 2011. It should be noted that when the SCR catalysts are new, the NH3 slip is typically very close to zero, but as the catalyst age approaches the replacement interval (typically 3 to 5 years), the slip will approach the proposed permit limit. As such, there is insufficient operating history at this time to support an NH3 slip limit of 2.0 ppmvd @ 15 percent O2 on a 1-hour averaging basis to consider it demonstrated in practice.

Therefore, the proposed 5.0 ppmvd @ 15 percent O2 limit based on a 1-hour averaging time is considered the most stringent NH3 slip limit achieved in practice for a large combined-cycle CT.

The DAQ agrees that the proposed Ammonia (NH3) Slip BACT limitations are reasonable considering the goals of BACT which takes "*into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*"

3.1(5.9) Secondary BACT for CT Startups/Shutdowns, Combustor Tuning and Commissioning

5.9.1 Secondary BACT for CT Startups and Shutdowns
The primary BACT emission limits discussed in earlier sections are either rate-based limits based on the combined-cycle CT heat input (lb/MMBtu) or concentration-based limits based on flue gas flow rate (ppmvd @ 15 percent O2). These limits reflect expected achievable emission rates using the respective control technology during periods of normal steady-state combined-cycle CT operation (between 50 and 100 percent load). However, these emission limits are not appropriate during periods of startup and shutdown. In these situations, the combustors do not operate at their maximum efficiency and, for CO, NOx, and VOC, emission concentrations are increased due to lower fuel input and exhaust flow. In addition, SCR and oxidation catalysts are not effective because the exhaust temperatures are generally too low to achieve effective control. Furthermore, until the turbine reaches DLN mode, it emits at a higher rate. This makes it impossible for the combined-cycle CTs to comply with stringent BACT limits applicable to steady-state operation during startup and shutdown periods.

In the definition of BACT, it clearly states that a BACT limit is one that, "on a case-by-case basis is determined to be achievable." Therefore, in order for NTE to propose limits that are both "achievable" and keep the combined-cycle CT under a high degree of control during normal steady-state operation, BACT limits applicable to normal steady state operations must not be applied to periods of startup and shutdown. Permitting of separate secondary limits is consistent with what has been proposed and accepted by other power generating facilities; the most recent and relevant examples for the proposed Project are the Moxie Liberty and Patriot Generating Stations (Plan Approval nos. 08-00045A and 41-00084A) and the LS Power Hickory Run project (Plan Approval no. 37-337A) in Pennsylvania and the Oregon Clean Energy Center (Permit to Install P0110840) and Carroll County Energy project (Permit to Install P0113762) in Ohio, all natural gas-fired combined-cycle projects in that were issued plan approvals in the last two years.

Secondary BACT limits are justified and, in cases such as CTs, are required to ensure with a necessary degree of confidence that the stringent primary BACT limits proposed in the previous sections are achievable for those pollutants with continuous compliance demonstration methods. NTE is proposing secondary NOx, CO, and VOC limits for startup and shutdown events that are mass-based limits on a pound per year basis. This is consistent with the above-referenced Moxie Liberty, Moxie Patriot and LS Power Plan Approvals. The pound per year emissions limits are based on worst-case assumptions on the numbers and types of startups and shutdowns for different operating scenarios (see Section 3.0 for discussion of methodology and estimates of total annual emissions) and CT vendor data on the durations and estimated emissions rates per startup/shutdown event. Compliance with these limits will be determined via CEMS for NOx and CO. For VOC, compliance will be determined by calculation (based on correlation between CO and VOC emissions developed from initial performance/diagnostic testing) and recordkeeping.

In addition, worst-case estimates of the pounds per event and duration of startups/shutdowns, based on vendor data, have been included in the air quality modeling analysis. Table 5-6 in the application summarizes the startup and shutdown emissions on a per-event basis used in the modeling. Three different startup scenarios (cold, warm, and hot) are included as well as one shutdown scenario. Based on the Project operating scenarios discussed in Section 3.1.3 and detailed in calculations provided in Appendix C, Table C-4 of the application, worst-case annual potential emissions have also been estimated based on different operating scenarios, including the numbers of each type of startup and shutdown. However, the number of each type of startup and shutdown is not proposed as a permit condition as these may vary. The proposed secondary BACT limits are instead mass-based limits that cap the total allowable emissions from all operating events. The proposed annual limits are provided in Table 5-5. In addition, NTE will agree to a maximum of 500 hours of startup/shutdown operations per year for the CT, which is consistent with conditions included in the Moxie and LS Power Plan Approvals.

Table 5-5 – Proposed Potential Annual Criteria Pollutant Emissions from CT+DB

Pollutant	MHPSA M501GAC - Total Annual Emissions for CT+DB For			
	Case A	Case B	Case C	Max.
NOx	63.1	97.0	103.4	103.4
CO	243.2	126.4	62.5	243.2
VOC	86.9	44.9	22.9	86.9
PM10/PM2.5	41.3	59.9	65.4	65.4
SO2	14.5	24.3	26.5	26.5
CO2	853,339	1,416,977	1,546,452	1,546,452

5.9.2 Combustor Tuning

Combustor tuning is required to maintain the CT in optimal operating condition. Tuning is performed periodically in response to turbine wear and variations in fuel, temperature, and humidity. The CT will be subject to stringent limits for startups and shutdowns in addition to stringent steady-state limits, so providing an allowance for tuning with alternative limits is necessary to assure compliance during the rest of the year.

Tuning involves testing and adjusting the different combustor operating modes and the transition from one mode to another. These operations are time-intensive and are expected to take up to 8 hours to complete. The tuning duration is due to the fact that the CT operating rate during the tuning is brought up slowly, approximately 5 MW at a time, and tuning is performed at each MW level. The CT is held at each load level while settings are varied to establish the optimal operating conditions. The complexity of the model-based control system requires tuning the CT at each operating point, which establishes tuning set points. The tuning set points are then saved in the plant control system algorithms and used during normal operation as the CT continuously and automatically tunes itself. Tuning would need to be performed up to two times per year.

Tuning has traditionally been performed during cold startups. Cold startups involve bringing the CT load up slowly and, therefore, provide an appropriate opportunity to conduct tuning. Recently, regulatory agencies have started imposing shorter time limits on cold startups, and so it has become increasingly difficult for operators to complete tuning within their cold startup time limits. Recent permits have, therefore, had to include specific provisions allowing for tuning operations outside of cold startups. Because tuning operations were originally conducted under cold startup limits, these provisions have typically provided for tuning operations to be subject to the same emissions limits applicable during cold startups. These limits are also generally appropriate for tuning because tuning involves low-load operation where emissions controls are not as effective, as is the case with cold startups. (Tuning takes longer than cold startups, however, because the CTs must be kept at each load level for a period of time while tuning takes place, and cannot be ramped up as soon as equipment conditions allow.)

5.10 Secondary BACT for CT Commissioning

The combined-cycle CT and associated equipment is highly complex and must be carefully tested, adjusted, tuned, and calibrated after the facility is constructed. These activities are generally referred to as “commissioning” of the facility. During the commissioning period, the CT needs to be fine-tuned at zero load, partial load, and full load to optimize its performance. The DLN combustors also need to be tuned to ensure that the CT runs efficiently while meeting both the performance guarantees and emission guarantees. In addition, the SCR systems and oxidation catalysts need to be installed and tuned.

The combined-cycle CT will not be able to meet the stringent BACT limits for steady-state operations during the commissioning period for a number of reasons. First, the SCR system and oxidation catalyst cannot be installed immediately when the CT is initially started up. There may be oils or lubricants in the equipment from the manufacture and installation of the equipment that would damage the catalysts if they were installed immediately. Instead, the CT needs to be operated without the SCR system and oxidation catalysts for a period of time to burn off any impurities that may be left in the equipment. In addition, once all of the pollution control equipment is installed, it needs to be tuned in order to achieve optimum emissions performance. Until the equipment is tuned, it will not be able to achieve the very high levels of emissions reductions reflected in the stringent BACT limits for normal operations.

Because the BACT limits established for normal operations are not technically feasible during the commissioning period, these limits are not BACT for this phase of the Project's operation. Alternate limits must, therefore, be specified for this mode of operation.

The only control technology available for limiting emissions during commissioning is to use best work practices to minimize emissions as much as possible during commissioning, and to expedite the commissioning process so that compliance with the stringent BACT limits for normal operations can be achieved as quickly as possible. There are no add-on control devices or other technologies that can be installed for commissioning activities.

To implement best work practices as an enforceable requirement, NTE is proposing conditions that will require the operators to minimize CT emissions to the maximum extent possible during commissioning. Commissioning emissions will also be subject to the annual emissions limits applicable to normal operations. All emissions from commissioning activities will be counted towards the facility's annual limits. Because commissioning is a relatively short-term period, it is expected that Project emissions will stay within those limits over the course of the entire year. Counting commissioning emissions towards the annual limits will also provide an additional incentive for the Project operator to minimize emissions as much as possible. Compliance with these proposed conditions for the commissioning period will be monitored by continuous emissions monitors that NTE will be required to install before any commissioning work begins, and through a written commissioning plan laying out all commissioning activities in advance.

The DAQ agrees that the proposed BACT standards and annual limits are reasonable considering the goals of BACT which takes "*into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*"

3.2(5.12) BACT for Auxiliary Boiler (ID No. ES-2) and Fuel Gas Fuel Gas Heater (ID No. ES-3)

The Project will include a 138 MMBtu/hr auxiliary boiler and a 9 MMBtu/hr fuel gas fuel gas heater, both exclusively fired with natural gas. The auxiliary boiler will operate as needed (less than the equivalent of 4,000 hours per year at maximum rated capacity) to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine during warm and hot starts. The fuel gas heater will operate as necessary (up to a maximum of 8,760 hours per year) to condition the natural gas prior to combustion to prevent condensation.

Combustion of natural gas in both units will yield emissions of NOx, SO2(H2SO4), PM10/PM2.5, CO, VOC and GHG, each subject to BACT (except SO2).

To support the BACT analyses, a search of the RBLC and other permits not included in the RBLC was performed for auxiliary boilers and fuel gas heaters at large combined-cycle power projects in the past five years. These determinations are summarized in Appendix D, Tables D-8 and D-9 of the application.

3.2(5.12.1) Auxiliary Boiler/Fuel Gas Heater NOx BACT

5.12.1.1 Identification of NOX Control Technologies (Step 1)

Potentially available control options for reducing NOx emissions from natural gas-fired auxiliary boilers and fuel gas heaters include:

- Low-NOX (LN) burner, typically with flue gas recirculation (FGR)
- Ultra-Low-NOX (ULN) burner
- Selective Catalytic Reduction (SCR)

Combustion controls, such as LN and ULN burners and FGR are designed to control thermal and/or fuel NOX formation by controlling the air-to-fuel ratio and combustion temperature. SCR is an add-on control used to remove NOX from the exhaust gas stream once it has been formed.

5.12.1.2 Technical Feasibility Analysis (Step 2)

Each of the identified controls are considered technically feasible. However, application of SCR to natural gas-fired boilers in this size range is unusual and application to a natural gas-fired fuel gas heater has not been identified.

5.12.1.3 Ranking of Controls (Step 3)

Based on a review of RBLC and other permit determinations, as summarized in Appendix D of the application, the ranking of technologies is as follows:

1. SCR: 5.0 ppmvd @ 3% O2 (~0.006 lb/MMBtu) is considered demonstrated for gas-fired boilers. SCR can be used as supplemental control with a LN burner, but has not been demonstrated with an ULN burner.
2. ULN burner: 9.0 ppmvd @ 3% O2 (~0.011 lb/MMBtu) is considered demonstrated for gas-fired boilers.
3. LN burner, typically with FGR: 30 ppmvd @ 3% O2 (~0.036 lb/MMBtu) is considered demonstrated for gas-fired boilers.

5.12.1.4 Evaluation of Most Effective Controls (Step 4)

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is summarized in Table 5-7 and Table 5-8 in the application for the auxiliary boiler and fuel gas heater, respectively. The cost impact analyses indicate that the overall cost effectiveness ratios of an SCR are excessive, at $21,600 per ton for the auxiliary boiler and $15,700 for the fuel gas heater. There are no energy or environmental issues with ULN burners that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

5.12.1.5 Selection of BACT
The lowest NOX limit identified for any auxiliary boiler or fuel gas heater at a combined-cycle power plant summarized in Appendix D, Tables D-8 and D-9 of the application, is consistent with the standard guarantee for ULN burners, which is 9 ppmvd at 3% O2, corresponding to 0.011 lb/MMBtu. NTE proposes to meet this most stringent limit with ULN burners to satisfy BACT requirements.

The DAQ agrees that the proposed NOx emissions limits are reasonable considering the goals of BACT which takes "*into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*"

3.2(5.12.2) Auxiliary Boiler/Fuel Gas Heater CO and VOC BACT

5.12.2.1 Identification of CO and VOC Control Technologies (Step 1)
Potentially available control options for reducing CO and VOC emissions from natural gas-fired auxiliary boilers and fuel gas heaters include:

- Combustion controls
- Oxidation catalysts

These technologies are fully described in Section 5.3.2 Identification of Available CO Control Technologies (for the Combustion Turbine).

5.12.2.2 Technical Feasibility Analysis (Step 2)
Each of the identified controls are considered technically feasible. However, application of oxidation catalysts to natural gas-fired boilers in this size range is unusual and application to a natural gas-fired fuel gas heater has not been identified. Use of an oxidation catalyst has been identified in only one draft permit for a natural gas-fired auxiliary boiler at a large combined-cycle power project (Footprint Power Salem Harbor Development project in MA), with a limit of 0.0035 lb/MMBtu for CO and 0.005 for VOC. NTE is not aware of any permit or installation of a fuel gas heater requiring use of an oxidation catalyst.

5.12.2.3 Ranking of Controls (Step 3)
Based on a review of RBLC and other permit determinations, as summarized in Appendix D, the ranking of technologies is as follows:

<u>CO:</u>
1. Oxidation catalyst: 0.0035 lb/MMBtu, based on a limit contained in the draft permit for the Footprint Power Salem Harbor plant. However, this plant has not been constructed and the limit is not considered demonstrated in practice.

2. Combustion controls: 50 ppmvd @ 3% O2 (~0.037 lb/MMBtu) is the most stringent limit contained in a permit for an auxiliary boiler or fuel gas heater equipped with an ULN burner. For the MEC Project, the most stringent CO emissions specification the owner's engineers was able to obtain was 0.08 lb/MMBtu.

<u>VOC:</u>
1. Combustion controls: 0.0015 to 0.006 lb/MMBtu is generally the range of VOC limits contained in permits for auxiliary boilers and fuel gas heaters, equipped with ULN burners at large combined-cycle projects.

5.12.2.4 Evaluation of Most Effective Controls (Step 4)
Since an oxidation catalyst is technically feasible for CO emissions from natural gas-fired auxiliary boilers and fuel gas heaters, an economic analysis of the cost effectiveness of CO control was conducted. This economic analysis is summarized in Table 5-9 and Table 5-10 of the application for the auxiliary boiler and fuel gas heater, respectively. The oxidation catalyst has been conservatively assumed to control 80% of the potential CO emissions starting with baseline emissions based on the ULN burner (reducing baseline emissions of 0.037 lb/MMBtu to 0.0074 lb/MMBtu for the auxiliary boiler and from 0.08 lb/MMBtu to 0.016 lb/MMBtu for the fuel gas heater). Table 5-9 and Table 5-10 indicate that the overall cost effectiveness ratios of oxidation catalysts in these cases are excessive, at $21,300 per ton for the auxiliary boiler and $44,800 per ton for the fuel gas heater. There are no energy or environmental issues with ULN burners that would indicate selection of oxidation catalysts as BACT, given the unfavorable economics.

5.12.2.5 Selection of BACT (Step 5)
The lowest CO limit identified for any auxiliary boiler or fuel gas heater at a combined-cycle power plant without an oxidation catalyst, as summarized in Appendix D, Tables D-8 and D-9, is 50 ppmvd at 3% O2, corresponding to 0.037 lb/MMBtu. However, for the KMEC Project, the most stringent CO emissions specification the owner's engineers was able to obtain was 0.08 lb/MMBtu. Based on excessive and unreasonable cost impact, use of oxidation catalysts were ruled out as BACT for both the auxiliary boiler and fuel gas heater. For VOC, the most stringent permit limits for auxiliary boilers and fuel gas heaters equipped with ULN is generally in the range of 0.0015 lb/MMBtu to 0.006 lb/MMBtu. Projects containing VOC limits at the lower end of this range have not yet been constructed and, therefore, are not considered demonstrated. Moreover, the more recent VOC permit limits are in 0.005 to 0.006 lb/MMBtu range. For CO, NTE proposes to meet 0.037 lb/MMBtu for the auxiliary boiler and 0.08 lb/MMBtu for the fuel gas heater. For VOC, NTE proposes 0.005 lb/MMBtu VOC as BACT for both units.

The DAQ agrees that the proposed CO and VOC emissions limits are reasonable considering the goals of BACT which takes *"into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."*

3.2(5.12.3) Auxiliary Boiler and Fuel Gas Heater PM10/PM2.5 BACT

For PM10/PM2.5, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for PM10/PM2.5 emissions from small natural gas-fired boilers and fuel gas heaters.

There are no applicable NSPS PM10/PM2.5 standards applicable to natural gas-fired equipment of the size range specified for the proposed auxiliary boiler or fuel gas heater. 15A NCAC 02D .503(c) would limit PM emissions from the boiler to 0.13 lb/MMBtu and from the fuel gas heater to 0.62 lb/MMBtu.

NTE proposes exclusive use of natural gas with a sulfur content of 0.7 grains/100 SCF in the auxiliary boiler and fuel gas heater to minimize emissions of PM10/PM2.5, which represents the most stringent controls available for this natural gas-fired equipment. The proposed PM10/PM2.5 emission limit, based on manufacturer specifications and the proposed sulfur content for both the auxiliary boiler and fuel gas heater is 0.007 lb/MMBtu. NTE proposes to meet the limit based on fuel sulfur monitoring/fuel supplier certifications.

Sulfur content in natural gas	0.7 grains/100 SCF (enforceable through fuel supplier certifications/monitoring records)
$PM/PM_{10}/PM_{2.5}$ (total filterables + condensables)	0.007 lb/MMBtu (estimated based on fuel sulfur content limit and manufacturer specifications). If necessary, initial stack testing would be performed using EPA Reference Methods 201 or 201A for filterable PM and Method 202 (revised 12/10/11 for condensable PM).

Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired combustion equipment. The practical limitation is considered region-specific, depending on the source/specifications of the natural gas in the pipeline supplying the plant. Based on a review of BACT determinations in EPA's RBLC and permits for boilers and fuel gas heaters not included in the RBLC, as summarized in Appendix D of the applicant, limits have been provided either for sulfur content or lb/MMBtu of PM10/PM2.5. Recent sulfur contents range from 0.1 to 2 grains/100 SCF and PM10/PM2.5 emission factors range from 0.0025 to 0.018 lb/MMBtu. The lowest limits identified are for the Green Energy Partners/Stonewall project in Leesburg, VA (0.002 lb/MMBtu, 0.1 grains S/100 SCF), the Palmdale Hybrid Power project in Palmdale, CA (0.003 lb/MMBtu) and the Portland, OR General Electric Carty Plant (2.5 lb/MMcf of natural gas, equivalent to 0.0025 lb/MMBtu). These limits are considered unrealistically low for a guarantee for a boiler or fuel gas heater of this type, based on a natural gas sulfur content of 0.7 grains/100 SCF. This is because of uncertainty and variability with available PM10/PM2.5 test methods, and the risk of artifact emissions resulting in a tested exceedance. All new gas-fired boilers, properly operated, are expected to have intrinsically low PM10/PM2.5 emissions. A limit of 0.007 lb/MMBtu is within the range of recent PSD BACT levels and is justified as PSD BACT based on the proposed sulfur content limit of 0.7 grains/100 SCF. More stringent listed PM10/PM2.5 emission limits in the RBLC are generally specific to projects with more stringent natural gas sulfur content specifications that are applicable to the geographic location of those projects. As PM10/PM2.5 emissions are directly affected by fuel sulfur content, the applicable emissions limitations must also be linked to those specifications.

The DAQ agrees that the proposed PM10/PM2.5 emissions limits are reasonable considering the goals of BACT which takes *"into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."*

3.2(5.12.4) Auxiliary Boiler and Fuel Gas Heater H2SO4 BACT

Emissions of SO2 and H2SO4 from the auxiliary boiler and fuel gas heater result from oxidation of fuel sulfur. For SO2 and H2SO4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for SO2 or H2SO4 emissions from small natural gas-fired boilers and fuel gas heaters.

There are no applicable NSPS SO2 or H2SO4 standards applicable to natural gas-fired equipment of the size range specified for the proposed auxiliary boiler or fuel gas heater. 15A NCAC 02D .0516 limits SO2 emissions from any combustion unit to 2.3 lb/MMBtu of heat input. NTE proposes exclusive use of natural gas with a sulfur content of 0.7 grains/100 SCF in the auxiliary boiler and fuel gas heater to minimize emissions of SO2 and H2SO4, which represents the most stringent controls available for this natural gas-fired equipment. The proposed SO2 emission limit is 0.002 lb/MMBtu, based on the assumption of 100 percent conversion of the sulfur in the fuel to SO2. The proposed H2SO4 emission rate, 0.00017 lb/MMBtu is based on an assumed 10 percent molar conversion of fuel sulfur to H2SO4. From review of the permit limits summarized in Appendix D, Tables D-8 and D-9 of the application for natural gas-fired auxiliary boilers and fuel gas heaters, the proposed limits are consistent with the most stringent limits identified, in consideration of the proposed fuel sulfur content of 0.7 grains/100 SCF.

The DAQ agrees that the proposed H2SO4 emissions limits are reasonable considering the goals of BACT which takes *"into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."*

3.2(5.12.5) Auxiliary Boiler and Fuel Gas Heater GHG BACT

GHG emissions from the auxiliary boiler and fuel gas heater result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for GHG emissions from small natural gas-fired boilers and fuel gas heaters.

With respect to GHG, most of the auxiliary boilers and fuel gas heaters listed in Appendix D of the application with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. The Project's proposed GHG limit for the auxiliary boiler and fuel gas heater is based on the USEPA Part 75 default emission factor (119 lb CO2/MMBtu) for natural gas combustion, which is consistent with the AP-42 emission factor found in Table 1.4-2 of Section 1.4. One unit listed in the RBLC (for the St. Joseph Energy Center in New Carlisle, IN) also has an 80% efficiency specified in addition to an annual mass limit. This is the only auxiliary boiler approved with this type of limit. The proposed Project will install an auxiliary boiler with a nominal efficiency of at least 80 percent. NTE proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (119 lb CO2/MMBtu). Based on the proposed annual fuel consumption limits for these units, total CO2e emissions would be limited to 32,945 TPY for the auxiliary boiler and 4,705 TPY for the fuel gas heater. The CO2e emissions from these units will be monitored by monitoring fuel use and using fuel-specific emission factors (e.g., AP42 Table 1.4-2 for CO2, CH4 and N2O) to calculate total CO2e on a 12-month rolling basis.

The DAQ agrees that the proposed GHG emissions limits are reasonable considering the goals of BACT which takes *"into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."*

3.3(5.11) BACT for Emergency Generator and Fire Pump Diesel Engines (ID Nos. ES-4 and ES-5)

The Project will include a maximum 1,850 BHP diesel engine powered emergency generator and a maximum 260 BHP diesel engine powered fire water pump. Both diesel engines will be run on ULSD, with a maximum sulfur content of 0.0015 weight percent (15 ppmw) as required under 40 CFR Part 60 Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, most recently amended January 30, 2013 (40 CFR Part 60 Subpart IIII).

The engines will operate for maintenance and testing purposes and during actual emergencies. Operation of the emergency generator and the fire pump engine will each be limited to 100 hours per year for maintenance checks and readiness testing purposes (i.e., not including actual emergencies). Combustion of the ULSD will yield emissions of NOx, SO2, PM10/PM2.5, CO, and VOC. The firewater pump and the emergency generator are subject to the emission requirements in EPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, most recently amended January 30, 2013 (40 CFR Part 60 Subpart IIII).

It is worth noting the relatively low contribution to the total emissions (tons per year) of these engines to the overall project. An abbreviated form of Table C-17 from the application is reproduced below.

Emission Unit	NOX	CO	VOC	SO2	PM10	PM2.5	H2SO4	Pb	GHGs (CO2e)	Total HAPs
Combustion Turbine w/ Duct Burner	103.4	243.2	86.9	26.5	65.4	65.4	20.3	0.004	1,676,538	6.6
Diesel Engine-Powered Emergency Generato	5.15	0.66	0.14	0.006	0.05	0.05	8.59E-04	2.9E-05	543	5.74E-03
Diesel Engine-Powered Fire Pump	0.43	0.17	0.017	0.001	0.021	0.02	1.02E-04	4.0E-06	75	1.80E-03
Total Project Emissions	**112.5**	**257.4**	**88.7**	**27.2**	**70.1**	**67.7**	**20.4**	**0.004**	**1,714,806**	**7.2**
% of overall project, emergency generator	4.6	0.3	0.2	0.0	0.1	0.1	0.0	0.8	0.0	0.1
% of overall project, firepump	0.38	0.07	0.02	0.00	0.03	0.03	0.00	0.11	0.00	0.02

Note that for both engines, NOx by far, represents the pollutant contributing the largest fraction to the overall project emissions. However, both engines put together contribute less than 5% to the potential annual emissions of NOx. Further, it is worth noting that it is not typical for emergency engines to operate 500 hours per year (i.e., hour per year of operation assumed for potential emission estimates, consistent with EPA and NCDAQ policy). Given the duty cycle of emergency engines, (e.g. short term, a few hours per month for maintenance and readiness testing in the absence of any emergency) it is clear, although they could contribute to short term NAAQS impacts, they would not be expected to be major contributors on an actual annual basis.

3.3(5.11.1) Emergency Diesel Engine NOx BACT

5.11.1.1 Identification of NOX Control Technologies (Step 1)

There are a limited number of available control technologies for diesel internal combustion engines used for limited or emergency operations. Potentially available control options for reducing NOx emissions from diesel engine emergency generators and fire pump engines include:

- Combustion controls
- Selective Catalytic Reduction
- Non-Selective Catalytic Reduction

Combustion Controls

Combustion control is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new engines include these features as standard equipment.

Selective Catalytic Reduction

SCR is a post-combustion NOx reduction technology and uses NH3 to react with NOx in the gas stream in the presence of a catalyst. NH3 and NOx react to form nitrogen and water. The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F. Typical catalyst material is titanium dioxide, tungsten trioxide, or vanadium pentoxide.

Non-Selective Catalytic Reduction

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. The catalyst requires that exhaust have more than 0.5 percent O2. This technique uses a fuel rich mixture that, combined with back pressure from exhaust flow through the catalyst, increases the brake specific fuel consumption of the engine. The method is not feasible with lean-burn internal combustion engines.

5.11.1.2 Technical Feasibility Analysis (Step 2)

Technical feasibility of the potential control options is evaluated below.

Combustion Controls

Combustion controls, which include combustion system design and proper operation and maintenance practices, have been applied successfully to diesel engines and are considered technically feasible for the emergency diesel engines.

SCR

SCR is not a demonstrated NOx control technology for emergency engines. In the United States, SCR has been applied to coal- and natural gas-fired electric utility boilers ranging in size from 250 to 8,000 MMBtu/hr. SCR has also been applied in base-load diesel engine applications where engines are operated primarily at high capacity for extended periods of time for industrial and power generation purposes. However, based upon a review of EPA's RBLC and other sources, no specific controls were identified for diesel engines operating less than 500 hours per year only for emergency operation purposes. Cost-effectiveness, evaluated on a cost per ton of pollutant controlled, would be unreasonably high for any of the add-on controls in this application. In addition, add-on controls such as SCR are not technically feasible in applications requiring quick startups and short operating durations. Therefore, the SCR technology is not considered to be technically feasible for the emergency engines.

NSCR

NSCR is considered to be not technically feasible due to the small size of the emergency engines and intermittent operations. The emergency engines will only operate about 2 hours a month for readiness testing and maintenance checks and up to 50 hr/year total.

5.13.1.3 Ranking of Remaining Controls (Step 3)

The only feasible control technology for the diesel-fired emergency engines is combustion controls. A review of BACT determinations for NOx emissions from emergency engines shows that combustion controls are the only technology considered technically feasible.

5.11.1.4 Evaluation of Most Effective Controls (Step 4)

There is no energy, economic, or environmental impacts that would preclude the selection of combustion controls as NOx BACT for the emergency engines proposed for the Project.

5.11.1.5 Selection of BACT (Step 5)

NTE proposes combustion controls and limited annual operating hours as BACT for the emergency engines, with NOx limits equivalent to the applicable NSPS Subpart IIII standards of 6.4 g/kW-hr and 4.0 g/kW-hr for NMHC + NOX from the emergency generator and fire water pump, respectively or a certified engine for which the manufacturer meets the applicable manufacturer FELs in 40 CFR 89.112(d).

The NC DAQ concurs with the proposed NOx BACT limitations considering the goals of BACT which takes "into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.3(5.11.2) Emergency Diesel Engine CO and VOC BACT

5.11.2.1 Identification of CO and VOC Control Technologies (Step 1)
CO and VOC emissions are a result of incomplete thermal oxidation of carbon contained within the fuel. Properly designed and operated engines typically emit low levels of CO and VOC. High levels of CO and VOC emissions could result from poor design or sub-optimal firing conditions.

The following control options are evaluated in the BACT analysis.

- Combustion controls
- Non-Selective Catalytic Reduction

Combustion Controls

Combustion controls, which include optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering CO and VOC emissions. Good combustion system design, which includes continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber is a standard feature of modern engines. As a result, CO and VOC emissions from modern engines are inherently low.

Non-Selective Catalytic Reduction

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than 0.5-percent O2 in the exhaust, which corresponds to fuel-rich operation. NSCR can simultaneously reduce NOx, CO, and hydrocarbons. The method is not feasible with lean-burn internal combustion engines.

5.11.2.2 Technical Feasibility Analysis (Step 2)
Technical feasibility of the potential control options is evaluated below.

Combustion Controls

Combustion controls, which include combustion system design and proper operation and maintenance practices, have been applied successfully to diesel engines and are considered technically feasible for the emergency diesel engines.

NSCR

NSCR is considered to be not technically feasible due to the small size of the emergency engines and intermittent operations. The emergency engines will only operate about 2 hours a month for readiness testing and maintenance checks and up to 50 hours per year total.

5.11.2.3 Ranking of Remaining Controls (Step 3)
The only feasible control technology for the diesel fired emergency engines is combustion controls. A review of BACT determinations for CO and VOC emissions from emergency engines shows that combustion controls are the only technology considered technically feasible.

5.11.2.4 Evaluation of Most Effective Controls (Step 4)

There is no energy, economic, or environmental impacts that would preclude the selection of combustion controls as CO and VOC BACT for the emergency engines proposed for the Project.

5.11.2.5 Selection of BACT (Step 5)
NTE proposes combustion controls and limited annual operating hours as BACT for the emergency engines, with CO limits equivalent to the applicable NSPS Subpart IIII standards. For the emergency generator, the applicable CO standard is 3.5 g/kW-hr and the NMHC + NOx standard is 6.4 g/kW-hr or the applicable FEL in 40 CFR 89.112(d). The NSPS standard for NMHC + NOx applicable to the fire pump engine is 4.0 g/kW-hr. There is no applicable CO standard for the fire pump engine.

The NC DAQ concurs with the proposed VOC and CO BACT limitations considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.3(5.11.3) Emergency Diesel Engine PM10/PM2.5 BACT

5.11.3.1 Identification of PM10/PM2.5 Control Technologies (Step 1)
A small amount of PM results from the combustion of diesel fuel in the emergency engines. EPA identifies two types of smoke that may be emitted from diesel engines during stable operations (i.e., blue smoke and black smoke). Per EPA's AP-42 Section 3.3 (Gasoline and Diesel Industrial Engines), blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion zone where mixtures are O_2 deficient.

The following control options are evaluated in the BACT analysis.

- Combustion controls
- Proper maintenance
- Add-On Controls

Combustion Controls
Carbon soot is formed in regions of combustion mixture that are O_2 deficient. Combustion controls, which include optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering carbon soot formation. Good combustion system design, which includes continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber is a standard feature of modern engines.

Proper Maintenance
Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Per EPA's AP-42 Section 3.3 (Gasoline and Diesel Industrial Engines), proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines.

Add-On Control Technologies
Modern internal combustion engine designs include good combustion controls and the uncontrolled PM emissions are very low. Based on the review of the RBLC database, no emergency engines have been permitted with add-on controls, such as diesel particulate filters (DPF). Therefore, no add-on controls are considered for the emergency engines proposed for the Project.

5.11.3.2 Technical Feasibility Analysis (Step 2)
Technical feasibility of the potential control options is evaluated below.

<u>Combustion Controls</u>
Combustion controls, which include combustion system design and proper operation and maintenance practices, have been applied successfully to diesel engines and are considered technically feasible for the emergency diesel engines.

<u>Proper Maintenance</u>
Proper maintenance is effective in minimizing particulate emissions and is considered technically feasible.

<u>Add-On Controls</u>
Add-on PM10/PM2.5 control devices are not considered for the emergency diesel engines of the Project. Consistent with this position and based on the information in EPA's RBLC database, no emergency diesel engine has been equipped with an add-on control device for PM control.

See NCDAQ comments in Section 5.11.3.5 below.

5.11.3.3 Ranking of Remaining Controls (Step 3)
The only feasible control technology for the diesel-fired emergency engines is combustion controls. A review of BACT determinations for PM emissions from emergency engines shows that combustion controls are the only technology considered technically feasible.

5.11.3.4 Evaluation of Most Effective Controls (Step 4)
There is no energy, economic, or environmental impacts that would preclude the selection of combustion controls as PM BACT for the emergency engines proposed for the Project.

5.11.3.5 Selection of BACT (Step 5)
NTE proposes combustion controls and limited annual operating hours as BACT for the emergency engines, with PM limits equivalent to the applicable NSPS Subpart IIII standards: 0.2 g/kW-hr for both the emergency generator and fire pump engine or the applicable FEL in 40 CFR 89.112(d).

The NCDAQ provides comment that although the RBLC database may not reflect add on controls as discussed by NTE, NSPS IIII provides for their uses to meet the relevant emission limitations if necessary. In general, emergency engines of this size are not tested in the field but rather the Permittee purchases an engine that meets the certification requirements in NSPS IIII. It has been the experience by the NCDAQ that some engines are equipped with PM filters in order to meet the applicable NSPS IIII emission standards. Even so, they would still be considered to just meet the same NSPS IIII emission limitation with no additional PM removal benefit.

However, given the marginal increase in PM reduction that would be achieved by add-On controls to an engine that is meeting the NSPS IIII standard without controls, the NC DAQ concurs with the proposed PM10/PM2.5 BACT limitations considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.3(5.11.4) Emergency Diesel Engine H_2SO_4 BACT

Emissions of SO_2 and H_2SO_4 from the diesel engines result from oxidation of fuel sulfur. For SO_2 and H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for SO_2 or H_2SO_4 emissions from small emergency diesel engines.

The applicable diesel fuel sulfur content specified by NSPS Subpart IIII is 15 ppm. 15A NCAC 02D .0516 limits SO_2 emissions from any combustion unit to 2.3 lb/MMBtu of heat input. The sulfur content of the ULSD fuel to be used in the emergency engines (15 ppm or 0.0015 percent) will comply with both standards.

NTE proposes exclusive use of ULSD with a sulfur content of 15 ppm to minimize emissions of SO_2 and H_2SO_4 from the emergency diesel engines, which represents the most stringent controls available for this equipment. The proposed SO_2 emission limit is 0.0017 lb/MMBtu, based on the assumption of 100 percent conversion of the sulfur in the fuel to SO_2. The proposed H_2SO_4 emission rate, 0.00021 lb/MMBtu is based on an assumed 10 percent conversion of fuel sulfur to SO_3 and 100 percent conversion of SO_3 to H_2SO_4.

The NC DAQ concurs with the proposed H_2SO_4 BACT limitations considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.3(5.11.5) Emergency Diesel Engine GHG BACT

GHG emissions from the emergency diesel engines result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for GHG emissions from small emergency diesel engines.

The Project's proposed GHG limit for both emergency diesel engines is based on the USEPA Part 75 default emission factor (165 lb CO_2/MMBtu) for distillate oil combustion, which is consistent with the AP-42 emission factor found in Table 3.4-1 of Section 3.4. Based on the proposed annual fuel consumption limits for these units, total CO_2e emissions would be limited to 543 TPY for the emergency generator and 75 TPY for the fire pump engine. The CO_2e emissions from these units will be monitored by monitoring fuel use and using fuel-specific emission factors (e.g., AP42 Table 3.4-1 for CO_2 and CH_4 and AP42 Table 1.3-8 for N_2O) to calculate total CO_2e on a 12-month rolling basis.

The NC DAQ concurs with the proposed GHG BACT limitations considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.4(5.13) BACT for Cooling Tower (ID No. ES-6) PM10/PM2.5

The Project will include a mechanical draft, counter flow, multi-cell cooling tower to provide steam condenser cooling needs for the power plant. In this type of cooling tower, fans at the top of each cooling tower cell maintain a flow of air through the cooling tower. Circulating water pumps move the water through the steam condenser, where it picks up heat, to the top of the cooling tower. At the top of the cooling tower, the warm water is distributed onto a perforated deck. The water then falls through the perforations and is cooled by evaporation as it fall through baffles (called "fill") to a basin at the bottom of the tower and air is induced up through the tower by the fans. Cool water from the cooling tower basin is returned to the condenser via the circulating water pumps.

Emissions from the cooling tower consist only of PM10/PM2.5. These emissions originate from the dissolved and suspended solids contained in droplets of cooling water, called "drift," that escape in the air stream exiting the cooling tower. Because drift droplets contain the same chemical impurities as the water circulating through the tower, these impurities can be converted to airborne emissions. The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and the efficiency of the drift eliminator. Drift eliminators are incorporated into the tower design to remove as many droplets as practical from the air stream before the air exits the tower. PM10/PM2.5 emissions from cooling towers are usually estimated by using the tower's design drift rate, the Total Dissolved Solids (TDS) concentration of the tower's incoming cooling water and the number of cycles of concentration in the tower. A high efficiency drift eliminator with a drift rate of 0.0005 percent is proposed for the Project.

5.13.1 Identification of Control Technologies (Step 1)

Potentially available control options for reducing PM/PM10/PM2.5 emissions from mechanical draft wet cooling towers are as follows:

- Air-Cooled Condensers (ACCs): This eliminates the use of circulating water for cooling and thus eliminates drift for large towers used for steam turbine condenser cooling
- High efficiency cooling tower drift eliminators.
- Reduction in the dissolved solids concentration in circulating water.

5.13.2 Technical Feasibility Analysis (Step 2)

Each of the identified controls are generally considered technically feasible. However, ACCs are typically only considered for projects where available water supply sources have insufficient capacity to meet project needs. They are typically not evaluated where sufficient water supply capacity is available due to increased size, costs, and energy impacts relative to wet cooling towers. Since the Project will be using local municipal water supply for its water needs, ACCs were not considered further for the Project or in this BACT analysis.

NTE is proposing use of high-efficiency drift eliminators. The only alternative would be to reduce the solids content of the water, either by water treatment or by reducing the cycles of concentration. NTE will be using the local municipal water supply for the Project, which will have a TDS content less than 100 mg/l. The maximum cycles of concentration will be maintained below 7.

5.13.3 Ranking of Controls (Step 3)

Based on a review of RBLC and other permit determinations, as summarized in Appendix D, Table D-10, the ranking of technologies is as follows:

1. High efficiency cooling tower drift eliminators: Generally recognized as capable of achieving a drift rate of 0.0005% of circulating water flow for large cooling tower used for power plant steam turbine condenser cooling.
2. Reduce the TDS in circulating water: Mechanical draft cooling towers are operated with circulating water TDS as low as 1000 milligrams/liter (mg/l).

5.13.4 Evaluation of Most Effective Controls (Step 4)
Based upon a review of PM10/PM2.5 emissions and controls identified from a search of EPA's RBLC and other permit determinations, drift eliminators and minimizing circulating water TDS are considered the only technically feasible options.

5.13.5 Selection of BACT (Step 5)
Appendix D includes a summary of PSD BACT determinations in the last five years for mechanical draft cooling towers at new large (> 100 MW) combustion turbine combined cycle projects. Review of the most recent BACT determinations in Appendix D of the application, Table D-10 of the application indicates that the wet cooling towers are commonly specified for 0.0005% drift. However, some of the determinations, particularly those for facilities in Texas, do not have the size of the tower indicated and only have lb/hr emissions, which does not provide a meaningful comparison. Therefore, NTE will specify high-efficiency drift eliminators, designed for 0.0005 percent drift loss for the wet cooling towers at the proposed facility.

With respect to the circulating water TDS concentration, for projects where this value is identified, these values range from 1000 to 6200 mg/l. As noted above, a collateral environmental impact of increasing the blowdown to decrease TDS is increasing water consumption. NTE is proposing 1000 mg/l as a reasonable maximum TDS value to balance drift emissions and water conservation.

The NC DAQ concurs with the proposed PM10/PM2.5 BACT limitations considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.5(5.14) BACT for GHG Emissions from Fugitive Natural Gas

The proposed project will include natural gas piping to transport fuel to all Project combustion equipment. Natural gas piping components, such as connections, valves, compressor seals, etc. are potential small sources of fugitive CH4 and CO2. In addition, intentional periodic purging of natural gas related to piping maintenance and turbine startups/shutdowns, as required for safety reasons, will also occur. The Project will implement best management practices, including routine inspections/monitoring to minimize fugitive leaks from the piping components

5.14.1 Identification of Available Control Technologies (Step 1)

Based on a review of recent BACT evaluations and determinations for combined-cycle power plants, the following technologies were identified as potential control options for piping fugitive emissions:

- Implementation of a leak detection and repair (LDAR) program using a hand held analyzer;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras; and
- Implementation of routine audio/visual/olfactory (AVO) walk-through inspections.

For purging of natural gas piping associated with piping maintenance and startups/shutdowns, which is necessary for safety reasons, the only available control option is to minimize startups and shutdowns to the extent that is practical within the context of the Project's operational scenarios and power contract obligations.

5.14.2 Elimination of Technically Infeasible Options (Step 2)

The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline natural gas is odorized with a small amount of mercaptan, AVO leak detection methods for natural gas piping components is also technically feasible.

5.14.3 Ranking of Remaining Control Technologies (Step 3)

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.36 Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges. The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.

5.14.4 Evaluation of Most Effective Controls (Step 4)

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed above, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

5.14.5 Selection of BACT (Step 5)

Since the uncontrolled CO2e emissions from the natural gas piping represent less than 0.02 percent of the total Project CO2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO2e emission reductions. Based on this top-down analysis, NTE proposes to implement daily AVO inspection walk-throughs as BACT for piping components in natural gas service. For purging of natural gas piping for piping maintenance and for startups/shutdowns, the standard industry work practice is the only practical means of minimizing emissions and is therefore considered to be BACT for the proposed project.

The NC DAQ agrees that the proposed strategy for minimizing GHG emissions from natural gas fugitive sources is BACT considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.6(5.15) BACT for SF6 Insulated Electrical Equipment Fugitive GHGs

The Project will use electrical circuit breakers insulated with sulfur hexafluoride (SF6), a regulated greenhouse gas (GHG). Annual potential fugitive emissions of SF6 from the circuit breakers and switchers, based on a maximum leakage rate of 0.5 percent per year, equate to about 0.004 percent of total Project GHG emissions. The proposed circuit breakers will be state-of-the art sealed units, equipped with low pressure alarms for leak detection and a low pressure lockout to minimize fugitive losses of SF6. This BACT analysis provides further justification of the circuit breaker design and controls.

5.15.1 Identification of Available SF6 Control Technologies (Step 1)

One technology is the use of state-of-the-art SF6 technology with leak detection to limit fugitive emissions. In comparison to older SF6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10 percent of the SF6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-GHG substance for SF6 as the dielectric material in the breakers. Potential alternatives to SF6 are reviewed in the National Institute of Standards and Technology (NIST) Technical Note 1425, Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6. These alternatives include use of dielectric oil or compressed air ("air blast") circuit breakers, which historically were used in high-voltage applications prior to the development of SF6 breakers, and the use of other non-GHG gases or gas mixtures in place of SF6.

5.15.2 Elimination of Technically Infeasible Options (Step 2)

According to the report NIST Technical Note 1425, SF6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF6-insulated equipment. "The use of SF6 insulation has distinct advantages over oil insulation, including none of the fire safety problems or environmental problems related to oil, high reliability, flexible layout, little maintenance, long service life, lower noise, better handling, and lighter equipment." In addition, "…for gas insulated circuit breakers there are still significant questions concerning the performance of gases other than pure SF6." The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF6.

5.15.3 Ranking of Remaining Control Technologies (Step 3)

The use of state-of-the-art SF6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

5.15.4 Evaluation of Most Effective Controls (Step 4)

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF6 as the dielectric material in the breakers is not considered technically feasible.

5.15.5 Selection of BACT and Determination of SF6 Limits (Step 5)

Based on this top-down analysis, NTE concludes that using state-of-the-art enclosed-pressure SF6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers. The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF6 emissions problems to light before a substantial portion of the SF6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF6 gas. This BACT determination is consistent with other recent determinations for fugitive SF6 emissions from circuit breakers – see, for example the BACT determinations for the Russell City Energy Center in Hayward, CA and the LaPaloma Energy Center in Harlingen, TX and Moxie Liberty and Moxie Patriot facilities in Pennsylvania.

NTE will monitor and report emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use. Annual SF6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD to Part 98, which requires tracking of the amount of SF6 dielectric fluid added to the circuit breakers for each month of facility operation.

The NC DAQ agrees that the proposed strategy for minimizing GHG emissions from insulated electrical equipment is BACT considering the goals of BACT which takes " into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant."

3.7 Air Dispersion Modeling Analysis

Introduction

The PSD modeling analysis described in this section was conducted in accordance with current PSD directives and modeling guidance. References are made to the Draft October 1990 EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting which will herein be referred to as the NSR Workshop Manual.

A summary of the modeling results is presented in the last topic, PSD Air Quality Modeling Results Summary. A detailed description of the modeling and modeling methodology is described below.

Project Description / Significant Emission Rate (SER) Analysis

NTE Carolinas, LLC (NTE) plans to construct and operate a natural gas-fired electric generating facility near Kings Mountain, NC. Operations are expected to occur 24 hours per day, 7 days per week and 52 weeks per year. A facility-wide pollutant netting analysis was accomplished and documented in Table 3-1 of the NTE permit application. Six pollutants were declared to exceed their PSD Significant Emission Rate (SER) and thus require a PSD analysis. These emission rates are provided in the table below.

Table 1 - Pollutant Netting Analysis

Pollutant	Annual Emission Rate (tons/yr)	Significant Emission Rate (tons/yr)	PSD Review Required?
NO_2	**112.5**	40	Yes
PM_{10}	**70.1**	15	Yes
$PM_{2.5}$	**67.7**	10	Yes
H_2SO_4	**20.4**	7	Yes
SO_2	27.2	40	No
CO	**257.4**	100	Yes
Total HAPs	7.2	10/25	No
Pb	0.004	0.6	No
VOC's	**88.7**	40	Yes

It should be noted that VOC's are not typically modeled as part of the PSD permitting process and given the fact that the emissions are less than the 100 TPY evaluation threshold established by USEPA, VOC's were not required to be evaluated further for this project. H_2SO_4 was evaluated under N.C.'s Toxics procedures and are discussed later in this document.

Preliminary Impact Air Quality Modeling Analysis

An air quality preliminary impact analysis was conducted for the pollutants exceeding their corresponding SERs. The modeling results were then compared to the applicable Significant Impact Levels (SILs) as defined in the NSR Workshop Manual to determine if a full impact air quality analysis would be required for that pollutant.

The NTE facility will be located near Kings Mountain, NC, in Cleveland County. The facility area is in the southwestern piedmont region with gently rolling terrain and is generally agricultural, industrial, and forest land. For modeling purposes, the area, including and surrounding the site, is classified rural, based on the land use type scheme established by Auer 1978.

NTE evaluated the pollutants' significant emissions using the EPA AERMOD model and five years (2008-2012) of National Weather Service (NWS) surface (Gastonia) and upper air (Greensboro) meteorological data. Full terrain elevations were included, as were normal regulatory defaults. Sufficient receptors were placed in ambient air beginning at the fenceline to establish maximum impacts. Emission rates for this specific project were used and the maximum impacts were then compared to the respective SIL. A load analysis was initially conducted to determine under which operating conditions maximum impacts for each pollutant and averaging period were expected to occur (details in Sect. 7.1.2 of the modeling report). Since the results showed impacts above the SILs for CO (1-hour), $PM_{2.5}$ (24-hour), and NO_2 (1-hour), further modeling was required for those pollutants. The SIL results are shown in Table 2.

Table 2 - Class II Significant Impact Results (ug/m^3)

Pollutant	Averaging Period	Facility maximum Impact	Class II Significant Impact Level	Significant Impact Distance (km)
PM_{10}	annual	0.2	1	0
	24-hour	3.1	5	0
$PM_{2.5}$	annual	0.12	.3	0
	24-hour	**1.9**	1.2	4.9
NO_2	annual	0.19	1	0
	1-hour	**66.9**	10	9.2
CO	1-hour	**2,159**	2000	2.2
	8-hour	77	500	0

Class II Area Full Impact Air Quality Modeling Analysis

A Class II Area NAAQS and PSD increment analysis was performed for CO, $PM_{2.5}$, and NO_2 to include offsite source emissions and background concentrations (NAAQS). NTE used AERMOD with the modeling methodology as described previously. Off-site source inventories for both increment and NAAQS modeling were obtained from NCDAQ, Mecklenburg County Air Quality Commission and SCDHEC and then refined by NTE using the NCDAQ approved "Q/D=20" guideline. In accordance with recent USEPA draft $PM_{2.5}$ modeling guidance, NCDAQ instructed NTE to address both primary and secondary formation of $PM_{2.5}$. As discussed in detail in Section 7.2.5 of the modeling report, it is not believed that secondary formation of $PM_{2.5}$ will contribute significantly to any violation of the 24-hour $PM_{2.5}$ NAAQS and no further evaluation of secondary formation was required.

NTE used an appropriate array of receptors beginning at the declared fenceline and extending outward to 20 kilometers. NO_2 and CO background concentrations were obtained from the Mecklenburg County monitor (ID 37-119-0041). The Gaston County monitor (ID 37-071-0016) was used for $PM_{2.5}$ background concentrations. The modeling results are shown in Table 3 and show that, although there were modeled exceedances of the NAAQS for $PM_{2.5}$, the NTE project did not contribute significantly to those exceedances since NTE's maximum contribution was less than the respective SIL for $PM_{2.5}$.

Table 3 - Class II Area NAAQS Modeling Results

Pollutant	Averaging Period	Maximum Onsite & Offsite Source + background Impacts (ug/m^3)	NAAQS (ug/m^3)	% NAAQS	Max. Project Impact (ug/m^3)	SIL (ug/m^3)	Proj. Impact Exceed SIL (Y/N)
$PM_{2.5}$	24-hour	88.81	35	254	0.613	1.2	No
NO_2	1-hour	171.79	188	91	N/A	N/A	N/A
CO	1-hour	6,825	40,000	17	N/A	N/A	N/A

For the CLASS II increment analysis for $PM_{2.5}$, NTE used the same onsite sources, fenceline, and receptors as in the NAAQS analysis. An offsite source inventory was constructed based on emissions information provided by NCDAQ, South Carolina DHEC, and Mecklenburg County AQC and was based on a $PM_{2.5}$ trigger date of January 6, 1975. Increment values have not been established by USEPA for either CO or the NO_2 1-hour averaging period. Details of the offsite source inventory for $PM_{2.5}$ are discussed in Sect. 14.0 of the modeling report. The Class II Area increment modeling results are shown in Table 4 and show that the NTE project does not contribute significantly to any exceedences of the $PM_{2.5}$ Class II Area increment.

Table 4 - Class II Area PSD Increment Modeling Results

Pollutant	Averaging Period	Maximum Onsite & Offsite Source Impacts (ug/m^3)	PSD Increment (ug/m3)	% Increment	Max. Project Impact (ug/m^3)	Proj. Impact Significant (exceed SIL?)
$PM_{2.5}$	24-hour	32.73	9	364	1.18	No

Non Regulated Pollutant Impact Analysis (North Carolina Toxics)

NTE also modeled six toxics using AERMOD with the same receptor array and meteorology as used in the NAAQS analysis. A list of the facility sources and emission rates used are attached to this document. All pollutants demonstrated compliance on a source-by-source basis with the NC's AAQS or Acceptable Ambient Level (AAL). The maximum concentrations are shown in Table 5.

Table 5 – Non-Regulated Pollutants Modeling Results

Pollutant	Averaging Period	Max Facility Impact (µg/m^3)	AAL (µg/m^3)	Percent of AAL
H_2SO_4	1-hour	5.84	100	6 %
	24-hr	3.5	12	29 %
Ammonia	1-hour	27.41	2,700	1 %
Formaldehyde	1-hour	0.77	150	<1 %
Arsenic	Annual	6.1e-06	0.0021	<1 %
Benzene	24-hr	4.6e-04	0.12	<1 %
Cadmium	24-hr	2.7e-05	0.0055	<1 %

Additional Impacts Analysis

Additional impact analyses were conducted for growth, soils and vegetation, and visibility impairment.

Growth Impacts

NTE is expected to employ approximately 25 to 30 full-time people, most of which are expected to come from the existing local population. Therefore, this project is not expected to cause a significant increase in growth in the area.

Soils and Vegetation

The facility is located in the southwestern piedmont area of North Carolina. The local geography is gently rolling terrain with a mix of forests, agricultural crops, and herbaceous vegetation. Section 10.2 of the modeling report provides a detailed discussion of the expected impacts on soils and vegetation in the project area. In summary, modeled impacts were well below EPA established thresholds for soil and vegetation effects; therefore, the NTE project is not expected to cause any detrimental impacts to soils or vegetation in the area.

Class II Visibility Impairment Analysis

A Level 1 and Level 2 VISCREEN analysis was conducted to determine if the NTE project is expected to affect any visibility sensitive areas near the project. Two state parks were identified to be of interest with respect to visibility impacts – Crowder's Mountain State Park in N.C. and Kings Mountain State Park in South Carolina. The Level 2 visibility analysis results provided in the modeling report show that the expected impacts to visibility will be well below the USEPA criteria for significant impacts.

Class I Area - Additional Requirements

There are five Federal Class I Areas within 300 km of the NTE project – Great Smokey Mountains National Park, James River Face Wilderness, Linville Gorge Wilderness Area, Joyce Kilmer – Slickrock Wilderness Area, and Cape Romain National Wildlife Refuge. The Federal Land Manager for each of those areas was contacted and none of them required any analysis; therefore, no analysis was conducted by the applicant.

CLASS I SIL Analysis

AERMOD was also used to estimate impacts for the Class I SIL analysis. Even though the distance to the closest Class I area to NTE, Linville Gorge Wilderness, exceeds 50 km, the threshold distance at which a long-range transport model is typically used, receptors were conservatively placed at 50 km from the NTE facility. NO_2, $PM_{2.5}$, SO_2, and PM_{10} all modeled below the EPA-established, CLASS I SILs, and thus no CLASS I increment modeling was required. Table 6 provides the results of SIL modeling.

Table 6 - Class 1 Significant Impact Results (ug/m^3)

Pollutant	Averaging Period	Max. Impact at 50 km	EPA SIL	% SIL
NO_2	Annual	0.0072	0.1	<1 %
SO_2	Annual	0.0018	0.1	2 %
	24-hour	0.018	0.2	9 %
	3-hour	0.071	1	7 %
PM_{10}	24-hour	0.055	0.32	17 %
	Annual	0.0047	0.20	2 %
$PM_{2.5}$	24-hour	0.051	0.07	73 %
	Annual	0.0043	0.06	7 %

PSD Air Quality Modeling Result Summary

Based on the PSD air quality ambient impact analysis performed the proposed NTE Carolinas, LLC facility will not cause or contribute to any violation of the Class II NAAQS, PSD increments, Class I Increments, or any FLM AQRVs. Tables showing the source parameters and emission rates used in the modeling are provided in the attached tables.

Source Parameters and Emission Rates

	Source ID	Easting (X)	Northing (Y)	Base Elevation	Stack Height	Temperature	Exit Velocity	Stack Diameter	**NO2**
		(m)	(m)	(m)	(m)	(K)	(m/s)	(m)	(lb/hr)
1	GW100F	467129.746	3895174.482	252.374	54.864	347.35	17.06882	7.01	28.38
2	GSU	467129.746	3895174.482	252.374	54.864	322.039	9.14058	7.01	46.75
3	DEWPT	467008	3895286	253.898	9.144	394.111	7.68073	0.61	0.10
4	AUXBOIL	467121.82	3895182.07	252.374	27.432	421.889	13.0803	1.366	1.52
5	GEN	467189	3895280	252.374	10.668	746.333	39.4	0.406	10.30
6	FP	467062.8	3895233.4	253.898	7.62	789.111	9.05528	0.305	0.85

	Source ID	Easting (X)	Northing (Y)	Base Elevation	Stack Height	Temperature	Exit Velocity	Stack Diameter	**CO**
		(m)	(m)	(m)	(m)	(K)	(m/s)	(m)	(lb/hr)
1	GW100F	467129.746	3895174.482	252.374	54.864	347.35	17.06882	7.01	17.06
2	GSU1	467129.746	3895174.482	252.374	54.864	345.956	9.14058	7.01	1486.15
3	DEWPT	467008	3895286	253.898	9.144	394.111	7.68073	0.61	0.72
4	AUXBOIL	467121.82	3895182.07	252.374	27.432	421.889	13.0803	1.366	5.11
5	GEN	467189	3895280	252.374	10.668	746.333	39.39532	0.406	1.33
6	FP	467062.8	3895233.4	253.898	7.62	789.111	9.05528	0.305	0.34

	Source ID	Easting (X)	Northing (Y)	Base Elevation	Stack Height	Temperature	Exit Velocity	Stack Diameter	**PM10/PM-2.5**
		(m)	(m)	(m)	(m)	(K)	(m/s)	(m)	(lb/hr)
1	GW100F	467129.746	3895174.482	252.374	54.864	347.35	17.06882	7.01	19.98
2	GA100F	467129.746	3895174.482	252.374	54.864	347.05	15.71163	7.01	19.49
3	GSU1	467129.746	3895174.482	252.374	54.864	345.956	13.97775	7.01	18.15
4	DEWPT	467008	3895286	253.898	9.144	394.111	7.68073	0.61	6.30E-02
5	AUXBOIL	467121.82	3895182.07	252.374	27.432	421.889	13.0803	1.366	9.66E-01
6	GEN	467189	3895280	252.374	10.668	746.333	39.39532	0.406	4.25E-03
7	FP	467062.8	3895233.4	253.898	7.62	789.111	9.05528	0.305	1.78E-03
8	COOL1	467125.3	3895322.2	252.374	12.652	-10	7.89432	10.859	2.08E-04
9	COOL2	467136.68	3895334.14	252.374	12.652	-10	7.89432	10.859	2.08E-04
10	COOL3	467148.08	3895346.054	252.374	12.652	-10	7.89432	10.859	2.08E-04
11	COOL4	467159.47	3895357.97	252.374	12.652	-10	7.89432	10.859	2.08E-04
12	COOL5	467170.86	3895369.88	252.374	12.652	-10	7.89432	10.859	2.08E-04
13	COOL6	467182.25	3895381.79	252.374	12.652	-10	7.89432	10.859	2.08E-04
14	COOL7	467193.64	3895393.71	252.374	12.652	-10	7.89432	10.859	2.08E-04
15	COOL8	467205.03	3895405.62	252.374	12.652	-10	7.89432	10.859	2.08E-04
16	COOL9	467216.42	3895417.53	252.374	12.652	-10	7.89432	10.859	2.08E-04

Toxic Emission Rates

Table G-12 Summary of Air Toxics Modeling Results

M501GAC Model Inqut File = Loadscr0812.adi

Stack qarameters for Model Inqut (1 CT/HRSG Unit) - Metric Units												
Ambient Temqerature	Summer				Average				Winter			
Case #	GS100F	GS100U	GS70U	GS50U	GA100F	GA100U	GA70U	GA50U	GW100F	GW100U	GW70U	GW50U
Duct Firing	ON	OFF	OFF	OFF	ON	OFF	OFF	OFF	ON	OFF	OFF	OFF
GT Load	100%	100%	70%	50%	100%	100%	70%	50%	100%	100%	70%	50%
Stack Height m.	54.86	54.86	54.86	54.86	54.86	54.86	54.86	54.86	54.86	54.86	54.86	54.86
Stack Diameter m.	7.01	7.01	7.01	7.01	7.01	7.01	7.01	7.01	7.01	7.01	7.01	7.01
Stack Temp. K	348.1	359.9	356.0	351.4	347.1	357.8	354.5	347.9	347.4	358.3	356.6	349.0
Stack Flow m3/sec	564.45	558.31	447.88	395.02	606.45	599.85	479.50	396.44	658.84	652.70	536.60	417.20
Stack Velocity m/sec	14.62	14.46	11.60	10.23	15.71	15.54	12.42	10.27	17.07	16.91	13.90	10.81
CT/DB MMBtu/hr	3112.4	2412.0	1768.0	1571.4	3409.0	2652.3	1938.0	1624.1	3602.5	2944.8	2195.8	1766.4
Sulfuric Acid (lb/MMBtu)	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03	1.5E-03
Sulfuric Acid g/sec (1-hr avg.)	0.60	0.47	0.34	0.30	0.66	0.51	0.37	0.31	0.70	0.57	0.42	0.34
Ammonia (lb/MMBtu)	7.3E-03	7.4E-03	7.5E-03	7.5E-03	7.1E-03	7.2E-03	7.3E-03	7.3E-03	7.2E-03	7.1E-03	7.2E-03	7.2E-03
Ammonia g/sec (1-hr avg.)	2.88	2.24	1.67	1.49	3.06	2.40	1.78	1.50	3.26	2.62	1.98	1.60
Formaldehyde (lb/MMBtu)	2.1E-04	2.1E-04	2.1E-04	2.1E-04	2.0E-04	2.0E-04	2.1E-04	2.1E-04	2.0E-04	2.0E-04	2.0E-04	2.0E-04
Formaldehyde g/sec (1-hr avg.)	0.08	0.06	0.05	0.04	0.09	0.07	0.05	0.04	0.09	0.07	0.06	0.05

Max. Normalized Impacts at 1 g/sec emission rate, AERMOD Refined Mode (5 Years) - 1 Unit (µg/m^3/(g/sec)):

Case #	GS100F	GS100U	GS70U	GS50U	GA100F	GA100U	GA70U	GA50U	GW100F	GW100U	GW70U	GW50U
1-hr	9.00	8.27	9.42	10.46	8.74	8.13	9.23	10.80	8.40	7.88	8.54	10.39
24-hr	5.40	4.96	5.65	6.28	5.24	4.88	5.54	6.48	5.04	4.73	5.12	6.23

AERMOD Screening Model Impacts - 1 Unit (µg/m^3):

Case #	GS100F	GS100U	GS70U	GS50U	GA100F	GA100U	GA70U	GA50U	GW100F	GW100U	GW70U	GW50U
Sulfuric Acid, 1-hr (µg/m3)	5.40	3.85	3.21	3.17	5.75	4.16	3.45	3.39	5.84	4.48	3.62	3.54
Sulfuric Acid, 24-hr (µg/m3)	3.24	2.31	1.93	1.90	3.45	2.50	2.07	2.03	3.50	2.69	2.17	2.12
Ammonia, 1-hr (µg/m3)	25.91	18.51	15.70	15.54	26.76	19.49	16.41	16.22	27.41	20.64	16.89	16.67
Formaldehyde, 1-hr (µg/m3)	0.73	0.52	0.44	0.44	0.76	0.55	0.46	0.46	0.77	0.58	0.48	0.47

Additional Annual Avg. Model Runs for Arsenic, Benzene and Cadmium

Modeled Emission Rates (g/sec):

	CT+DB	Boiler	Dew Pt. Heater	Emerg. Gen.	Fire Pump
Arsenic, annual avg.	8.07E-05	1.56E-06	2.22E-07	3.77E-07	5.18E-08
Benzene, annual avg.	4.54E-03	1.64E-05	2.34E-06	7.31E-05	1.21E-05
Cadmium, annual avg.	4.40E-04	8.50E-06	1.21E-06	2.83E-07	3.88E-08

Model Results:

Pollutant	Max. Impact (µg/m3)	AAL (µg/m3)
Sulfuric Acid, 1-hr avg.	5.84	100
Sulfuric Acid, 24-hr avg.	3.50	12
Ammonia , 1-hr avg.	27.41	2700
Formaldehyde, 1-hr avg.	0.77	150
Arsenic, annual avg.	6.1E-06	0.0021
Benzene, annual avg.	4.6E-04	0.12
Cadmium, annual avg.	2.7E-05	0.0055

Attachment B

Permit Review for Permit No. 10400R01
Application No. 2300383.17A)

NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: **January 16, 2018**

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300383
Inspector's Name: Bob Caudle
Date of Last Inspection: 10/31/2017
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Kings Mountain Energy Center

Facility Address:
Kings Mountain Energy Center
180 Gage Road
Kings Mountain, NC 28086

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

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

Permit Applicability (this application only)

SIP:
NSPS:
NESHAP:
PSD:
PSD Avoidance:
NC Toxics:
112(r):
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Matthew Hickey EHS Manager (980) 785-9404 181 Gage Road Kings Mountain, NC 28086	Michael Green Vice President (904) 687-1857 24 Cathedral Place St. Augustine, FL 32084	Brandon Mogan (803) 422-5251 140 Stoneridge Drive Columbia, SC 29210

Application Data

Application Number: 2300383.17A
Date Received: 10/16/2017
Application Type: Modification
Application Schedule: State
Existing Permit Data
Existing Permit Number: 10400/R00
Existing Permit Issue Date: 04/15/2015
Existing Permit Expiration Date: 03/31/2023

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP

No emissions inventory on record. The emissions inventory is due June 30th of every year.

Review Engineer: Joseph Voelker

Review Engineer's Signature: Date:

Comments / Recommendations:
Issue 10400/R01
Permit Issue Date: January 16, 2018
Permit Expiration Date: March 31, 2023

I. Introduction and Purpose of Application

As stated in the application….
NTE Carolinas, LLC (NTE) is constructing, and will operate, a natural gas-fired combined-cycle power plant known as the Kings Mountain Energy Center (KMEC or Facility). KMEC is located at 181 Gage Road near the City of Kings Mountain in Cleveland County, North Carolina. The Facility received a Prevention of Significant Deterioration (PSD) Air Quality Permit (No. 10400R00) in April of 2015 (Facility ID: 2300383).

The original PSD construction permit application included a 138 million Btu per hour (MMBtu/hr) Auxiliary Boiler (ES-2) and an 1,850 brake horsepower (bhp) Emergency Generator (ES-4). NTE is proposing to install an auxiliary boiler and emergency generator that are smaller than what NTE applied for in the construction permit application.

The current PSD permit limits the Diesel Emergency Generator (ES-4) and Diesel-fired Emergency Fire Pump (ES-5) to 30 minutes per hour of non-emergency operation. Additionally, the permit does not allow ES-4 and ES-5 to operate simultaneously. These limits do not provide adequate working time for commissioning of the engines. It is requested that during initial commissioning of these engines, the diesel emergency generator be allowed to operate up to 40 hours and the emergency fire pump be allowed to operate up to 30 hours. The commissioning tests of the engines will only be conducted when the Combustion Turbine (CT) and Auxiliary Boiler at the facility are not operating. Therefore, the commissioning tests are not expected to impact results of NAAQS compliance modelling submitted and approved with the PSD permit application.

These permit modifications will be discussed further below.

II. Chronology

Date	Description
October 18, 2017	An application was received and assigned application no. 2300383.17A. The application was missing the processing fee. Application was placed on HOLD.
November 1, 2017	Application fee was received. Application was placed IN PROGRESS.
November 21, 2017	Draft sent to Permittee
December 8, 2017	Comments received from Permittee

III. Modification Description and Regulatory Review

<u>Boiler ES-2</u>

Boiler ES-2 was originally permitted as follows:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-2	Natural Gas-fired Auxiliary Boiler with Low NOx burners (138 MMBtu/hr maximum heat input)	NA	NA

The Permittee would like to install the following boiler instead.

Emission Source ID No.	**Emission Source Description**	**Control Device ID No.**	**Control Device Description**
ES-2	Natural Gas-fired Auxiliary Boiler with Low NOx burners (42.8 MMBtu/hr maximum heat input)	NA	NA

The Permittee states in the application…

> As part of the Facility, the natural gas-fired Auxiliary Boiler will primarily be used to provide high-temperature steam when the CT is offline. The steam will assist in a more rapid startup of the Steam Turbine after extended shutdowns and potentially provide heating for fuel gas at the Facility. Although there may be some overlapping operation during startup and shutdown of the CT, the auxiliary boiler will not operate once the CT has achieved steady-state operations. Once the Facility has achieved production of electricity for sale, total operation of the Auxiliary Boiler is anticipated to be less than 4,000 hours per 12-month period.

The following table shows the hourly emissions and annual emissions at the permitted 4000 hours of operation per year.

Table 3-1: Auxiliary Boiler Estimated Emissions

Pollutant	Emissions (lb/hr)	Emissions (tons/year)
NO_x	0.47	0.94
CO	1.58	3.17
VOC	0.21	0.43
PM_{10}	0.30	0.60
$PM_{2.5}$	0.30	0.60
SO_2	0.025	0.05
H_2SO_4	0.01	0.02
Lead	2.09E-05	4.18E-05
POM/PAH	3.69E-06	7.38E-06
NH_3	0.13	0.27
Single HAP (Hexane)	0.08	0.15
Total HAPs	0.08	0.16

The following table shows the changes in emissions on an annual basis associated with the installation of the smaller boiler. Note that this assumes the emission factors are the same for both boilers. This will be discussed elsewhere.

Table 3-2: Auxiliary Boiler Emissions Change

	138 MMBtu/hr Auxiliary Boiler	**42.8 MMBtu/hr Auxiliary Boiler**	**Change**
Pollutant	**Emissions (tons/year)**	**Emissions (tons/year)**	**tons/year**
NO_x	3.04	0.94	**-2.10**
CO	10.21	3.17	**-7.04**
VOC	1.38	0.43	**-0.95**
PM_{10}	1.93	0.60	**-1.33**
$PM_{2.5}$	1.93	0.60	**-1.33**
SO_2	0.55	0.05	**-0.50**
H_2SO_4	0.07	0.02	**-0.05**
Lead	1.30E-04	4.18E-05	**-8.82E-05**
POM/PAH	2.40E-05	7.38E-06	**-1.66E-05**
NH_3	0.86	0.27	**-0.59**
Single HAP (Hexane)	0.49	0.15	**-0.34**
Total HAPs	0.51	0.16	**-0.35**

<u>Regulatory review for Boiler ES-2</u>

15A NCAC02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
This rule limits PM emissions from fuel burning heat exchangers by the following equation:

E = 1.090*(Q)^(-0.2594) Equation 1
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

Pursuant to02D .0503(e):

<u>The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site</u> which are in operation, under construction, or permitted pursuant to 15A NCAC 2Q, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter <u>for each fuel burning indirect heat exchanger.</u>

For purposes of this rule, there are three fuel burning indirect heat exchangers at the proposed site,

Auxiliary boiler -	42.8 MMBtu/hr
Fuel gas heater –	9 MMBtu/hr
Heat recovery steam generator (HRSG) –	<u>704 MMBtu/hr</u>
Total =	755.8 MMbtu/hr

Using equation 1 above, the allowable PM emission rate from each of these sources is: 0.20 lb/MMBtu.

Based on the original BACT analyses for the boiler and fuel gas heater the Permittee has the following permit emission limitations:

Auxiliary boiler -	0.007 lb/MMBtu
Fuel gas heater –	0.007 lb/MMBtu

These emission limitations are enforced through the PSD permit conditions (2D .0530). The Permittee is not requesting to revise the BACT emission limitations for the boiler. Given the expected margin of compliance no additional monitoring, recordkeeping and reporting with respect to02D .0503 will be required.

15A NCAC02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
15A NCAC02D .0521: CONTROL OF VISIBLE EMISSIONS
Changing to a smaller size boiler does not affect the facility's compliance status with respect to these regulations. The boiler will still fire natural gas which has a very low sulfur content and typically results in a plume with very low (if any) visible emissions

15A NCAC02D .0524: NEW SOURCE PERFORMANCE STANDARDS
The current boiler is subject to NSPS Subpart Db. The new boiler however, will be subject to NSPS Subpart Dc. Firing only natural gas, the Permittee must only keep monthly fuel records. Compliance with this rule is expected.

15A NCAC02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
The boiler was part of the original facility (project) that was subject to PSD review. The boiler was not constructed so for all intents and purposes this smaller boiler being constructed in its place is part of the original project. This boiler is a natural gas -fired boiler with low NOx burners. The Permittee is not requesting to revise any of the BACT emission limitations originally imposed. The following table are the BACT limits for the currently permitted boiler.

Regulated Pollutant	BACT Limits*	BACT Technology
PM_{10}, $PM_{2.5}$	0.007 lb/MMBtu	Exclusive natural gas–firing
H_2SO_4	0.7 grains S per 100 SCF natural gas combusted	Exclusive natural gas–firing
NO_x,	9 ppmvd @ 3% O2 (0.011 lb/MMBtu)	Ultra low NOx burners
CO	50 ppmvd @ 3% O2 (0.037 lb/MMBtu)	Good combustion practices
VOC	0.005 lb/MMBtu	Good combustion practices
GHGs	32,945 tpy of CO2e	Exclusive natural gas–firing

If this boiler was included in the original BACT analyses it is likely that the same BACT limits would have been imposed. Note that the pollutant of greatest concern, NOx, with a BACT emission limitation of 0.011 lb/MMBtu, is expected to have hourly emissions of 0.47 lb/hr and at 4000 hours per year potential operation annual emissions of less than 1 ton per year. Since the emissions are proportional to heat input, the use of this boiler represents an hourly and annual reduction of emissions over the previous emission estimates for the auxiliary boiler for all pollutants. Given the low emission rates for all pollutants and that the emission rates are being reduced over those included in the previous BACT and modeling analyses, a re-visitation of the BACT and modeling analyses are not justified with the exception of GHGs. The BACT limit chosen is simply an annual emission rate proportional to heat input. The new heat input is 0.31 (42.8/138) of the previously permitted boilers heat input. Thus, the revised GHG BACT limit is 10, 218 tpy of CO2e.

As discussed above, the smaller boiler will now be subject to NSPS Subpart Dc. The boiler currently permitted was subject to NSPS subpart Db which contained a NOx limitation and the associated monitoring, recordkeeping and reporting. The monitoring for the PSD BACT limitation was streamlined to reference the NSPS Subpart Db monitoring recordkeeping and reporting requirements. Since the NSPS Subpart Db requirements are no longer required the monitoring recordkeeping and reporting for NOX must be revised.

At the other recently permitted NTE facility (NTE – Reidsville Energy Center permit R00 recently issued on April 21, 2017), the monitoring and recordkeeping for the auxiliary boiler and fuel gas heater (with similar BACT limits as those at this facility) included the following language, which is essentially good combustion practices and proper operation and maintenance language. It reads:

i. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the boiler including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

j. The Permittee shall perform inspections and maintenance as recommended by the manufacturer. 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:
   i. the date and time of each recorded action;
   ii. the results of each inspection; and
   iii. the results of maintenance performed.

In hindsight, this language should have been included in the original permit. This language will be applied to the revised permit.

Emergency Engine ES-4

Engine ES-4 was originally permitted as follows:

Emission Source ID No.	**Emission Source Description**	**Control Device ID No.**	**Control Device Description**
ES-4	Diesel Fuel-fired Standby Emergency Generator (1,850 maximum brake horsepower)	NA	NA

The Permittee would like to install the following engine instead.

Emission Source ID No.	**Emission Source Description**	**Control Device ID No.**	**Control Device Description**
ES-4	Diesel Fuel-fired Standby Emergency Generator (1,528 maximum brake horsepower)	NA	NA

The permittee is simply installing a smaller emergency generator than it had originally permitted. The Permittee also states in the application…

> The current PSD permit limits the Diesel Emergency Generator (ES-4) and Diesel-fired Emergency Fire Pump (ES-5) to 30 minutes per hour of non-emergency operation. Additionally, the permit does not allow ES-4 and ES-5 to operate simultaneously. These limits do not provide adequate working time for commissioning of the engines. It is requested that during initial commissioning of these engines, the diesel emergency generator be allowed to operate up to 40 hours and the emergency fire pump be allowed to operate up to 30 hours. The commissioning tests of the engines will only be conducted when the Combustion Turbine (CT) and Auxiliary Boiler at the facility are not operating. Therefore, the commissioning tests are not expected to impact results of NAAQS compliance modelling submitted and approved with the PSD permit application.

Upon review the operating limitations imposed in the initial permit were not intended to restrict operations during the commissioning phase of construction. This has implications only with respect to the 02D .0530 (PSD) and 02D .0524 (NSPS Subpart Dc) permit conditions. See regulatory review discussion below.

The following table shows the hourly emissions and annual emissions at 500 hours of operation per year, the accepted hours of operation of emergency service engines for potential emissions purposes.

Table 3-3: Emergency Generator Estimated Emissions

Pollutant	Emissions (lb/hr)	Emissions (tons/year)
NO_x	12.40	3.10
CO	0.88	0.22
VOC	0.07	0.0168
PM_{10}	0.13	0.0337
$PM_{2.5}$	0.13	0.0337
SO_2	0.02	0.0046
H_2SO_4	1.85E-03	0.00046
Lead	9.93E-05	2.48E-05
POM/PAH	2.34E-03	5.85E-04
NH_3	0.52	0.13
Single HAP (Benzene)	8.56E-03	2.14E-03
Total HAPs	1.74E-02	4.34E-03

The following table shows the changes in emissions on an annual basis associated with the installation of the smaller engine. Note that this assumes the emission factors are the same for both engines which is a reasonable assumption. This will be discussed elsewhere.

Table 3-4: Emergency Generator Emissions Change

Pollutant	1,850 bhp Generator Emissions (tons/year)	1,528 bhp Generator Emissions (tons/year)	Change Tons/year
NO_x	5.15	3.10	**-2.05**
CO	0.66	0.22	**-0.44**
VOC	0.14	0.02	**-0.12**
PM_{10}	0.05	0.03	**-0.02**
$PM_{2.5}$	0.05	0.03	**-0.02**
SO_2	5.61E-03	4.62E-03	**-9.90E-04**
H_2SO_4	6.88E-04	4.62E-04	**-2.26E-04**
Lead	2.90E-05	2.48E-05	**-4.20E-06**
NH_3	0.15	0.13	**-0.02**
Single HAP (Benzene)	2.50E-03	2.14E-03	**-3.60E-04**
Total HAPs	5.60E-03	4.70E-03	**-9.00E-04**

Regulatory review for Emergency Engine ES-4

15A NCAC02D .0521: CONTROL OF VISIBLE EMISSIONS
In the current permit this rule does not apply to the existing ES-4. This is incorrect. Under NSPS Subpart III constant speed engines of this size and year are exempt from the smoke (read opacity) standards at 40 CFR 89.113. Therefore 02D .0521 does apply. Even so, consistent with current permitting policy, internal combustion emergency engines are not subject to any monitoring recordkeeping or presorting requirements. This discussion also applies to the revised ES-4. The permit will be revised accordingly.

15A NCAC02D .0524: NEW SOURCE PERFORMANCE STANDARDS for EMERGENCY GENERATOR (ID No. ES-4)
Although the engine size and model year has changed, the permit condition is structured such that no changes are necessary to the permit. The application included the appropriate certificate of conformity for the engine. The currently permitted engine and the new engine have identical emission limitations.

This rule limits operation during non-emergency service. As discussed above the Permittee is requesting that during initial commissioning of these engines, the diesel emergency generator be allowed to operate up to 40 hours and the emergency fire pump be allowed to operate up to 30 hours. Upon review, the EPA does not view commissioning of the engines as initial startup[1]. As such the operating restrictions in the current permit condition do not apply during commissioning. No changes are necessary to the permit.

15A NCAC02D .1111 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR 63, Subpart ZZZZ, "National Emission Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines")

This smaller engine has the same requirements as the previously permitted engine. It simply must comply with NSPS Subpart IIII. No changes to the permit are necessary.

15A NCAC02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

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[1] Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines And New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013

The BACT limits for the currently permitted engine are simply the NSPS Subpart IIII emission limitations. To comply, the permittee must satisfy the NSPS Subpart IIII monitoring, recordkeeping and reporting requirements. The new smaller engine is subject to the same NSPS emission limitations. Hence, if this engine was included in the original analysis it would have resulted in the same BACT limits (except GHG, see below). Given the low emission rates for all pollutants and that the emission rates are being reduced over those included in the previous BACT and modeling analyses, a re-visitation of the BACT and modeling analyses are not justified, with the exception of GHGs. The BACT limit chosen is simply an annual emission rate proportional to heat input (or brake horsepower). The new brake horsepower is 0.83 (1528/1850) of the previously permitted engine's brake horsepower. Thus, the revised GHG BACT limit is 449 tpy of CO2e.

As discussed elsewhere the Permittee is requesting that during initial commissioning of this engine and the fire pump engine ES-5, the diesel emergency generator be allowed to operate up to 40 hours and the emergency fire pump be allowed to operate up to 30 hours. Upon review, the intent of the operating restrictions was not to apply during commissioning. The same such conclusion was documented in an email from William Willets during the NTE Reidsville Energy Center Project dated March 22, 2017. It reads:

> Anything prior to commencing normal operation is not subject to modeling or BACT considerations. In keeping with the SCAQMD decision, I would ask that you give us an idea of the amount of time that will be required to complete commissioning of the engines. This will become an enforceable condition of the permit with notifications of the beginning and end of the commissioning period required. In addition, we will clarify any modeling/BACT conditions such that it is clear that those do not apply during commissioning.

In the NTE Reidsville permit, the expected hours of commissioning were included in the permit with the following language:

> **<u>Operating Restrictions</u>**
>
> e. The Permittee shall limit the operation of these engines as follows:
>   i. Operation of each engine shall be limited to 30 minutes per hour of non-emergency operation; and
>   ii. The engines shall not operate simultaneously during non-emergency operation.
>   iii. For purposes of initial commissioning of these engines, Section 2.1 C.5e.i does not apply. Engine (ID No. ES-4) may operate up to 40 hours for purposes of initial commissioning. Engine (ID No. ES-5) may operate up to 30 hours for purposes of initial commissioning.

This language along with the associated recordkeeping and reporting will be incorporated into the revised permit.

IV. NSPS, NESHAPS, PSD, Toxics, Attainment Status, 112(r), and CAM

<u>NSPS</u>
Relevant NSPS applicability is discussed in Section III.

<u>NESHAP/MACT</u>
The facility is a minor source of HAP.
Relevant MACT applicability is discussed in Section III.

<u>PSD</u>
Cleveland County is in attainment for all pollutants. The facility is a PSD major source. Relevant PSD applicability is discussed in Section III.

<u>CAM</u>
CAM will be addressed during the initial TV permitting process.

<u>112r</u>
The Permittee is not subject to Section 112(r) of the Clean Air Act requirements because of the following explanation as provided in the original application:

> NTE is proposing to use a dilute (19 percent by weight) solution of aqueous ammonia for the SCR NOx control system in lieu of anhydrous or higher concentration aqueous ammonia solutions, which are regulated under RMP if used or stored in amounts greater than 10,000 pounds (anhydrous ammonia) or 20,000 pounds (aqueous ammonia in concentrations of 20 percent or greater). Therefore, the RMP regulations will not be applicable to the Project.

<u>Toxics</u>
The proposed changes will result in a decrease of all TAPs. No modeling review is necessary.

V. Compliance History

The facility is under construction and has not commenced operation.

VI. Changes Implemented in Revised Permit

Existing Condition No.	New Condition No.	Changes
Cover Letter	Cover Letter	• Used current shell language, updated permit numbers, dates, etc. • Correct address to 181 Gage Road
Permit page one	Same	• Revised dates, permit numbers, etc. using current shell standards • Correct address to 181 Gage Road
Section 1 – Permitted Equipment list	Same	• Revised ES-2 heat input from 138 to 42.8 MMBtu/hr • Revised ES-4 brake horsepower from 1,850 to 1,528
Section 2.1 A.3.h.	Same	• Corrected regulatory reference from §60.8(b) to §60.7(b)
Section 2.1 A.4.a	Same	• Corrected Table 4.a GHG limits to incorporate “ less than or equal to”
Section 2.1 A.4.j(C)	Same	• Corrected typographical error of “municipal; waste combustor unit” to “emission source (ID No. ES-1)”
Section 2.1 A.1.a and B.1 a	Same	• Revised emission limitation from 0.19 to 0.2 lb/MMBtu
Section 2.1 B.5	Same	02D .0530 condition for boiler ES-2
a	Same	• revised GHG BACT limit to 10, 218 tpy of CO2e
e through i	5.e through i	• Revised the monitoring and recordkeeping requirements for the boiler to include good combustion practices and good operation and maintenance requirements.
j, k and l	5.j	• Clarified the reporting requirements for the boiler
Section 2.1 B 6	Same	• 02D .0530 condition for fuel heater ES-3
g	g and h	• Revised the monitoring and recordkeeping requirements for the fuel heater to include good combustion practices and good operation and maintenance requirements.

Existing Condition No.	New Condition No.	Changes
i and g (typos)	i	• Fixed numbering typo and clarified reporting requirement
Section 2.1 C.1.a	Same	• The condition was revised to reference "these sources" instead of just ES-5.
section 2.1 C.5	Same	02D .0530 condition
a	Same	• Revised GHG BACT from 543 to 449 tpy of CO2e
a and b	Same	• fixed typographical error. Th BACT technology for GHGs should be good combustion practices. •
NA	e.iii	• The following language was added: For purposes of initial commissioning of these engines, Section 2.1 C.5e.i does not apply. Engine (ID No. ES-4) may operate up to 40 hours for purposes of initial commissioning. Engine (ID No. ES-5) may operate up to 30 hours for purposes of initial commissioning.
NA	g and h	• Added recordkeeping and reporting requirements to accommodate the operation during commissioning

VII. Public Notice/EPA and Affected State(s) Review

Not applicable.

VIII. Recommendations

Issue permit no. 10400R01.

Attachment C

Permit Review for Permit No. 10400R02
(Application No. 2300383.18B)

NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: **January 10, 2019**

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300383
Inspector's Name: Bob Caudle
Date of Last Inspection: 10/02/2018
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Kings Mountain Energy Center

Facility Address:
Kings Mountain Energy Center
181 Gage Road
Kings Mountain, NC 28086

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

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

Permit Applicability (this application only)

SIP:
NSPS:
NESHAP:
PSD: 02D .0530
PSD Avoidance:
NC Toxics:
112(r):
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Jim Medford Project Manager (704) 259-7915 181 Gage Road Kings Mountain, NC 28086	Michael Green Vice President (904) 687-1857 24 Cathedral Place, Suite 300 St. Augustine, FL 32084	Matthew Hickey EHS Manager (410) 459-9594 181 Gage Road Kings Mountain, NC 28086

Application Data

Application Number: 2300383.18B
Date Received: 10/09/2018
Application Type: Modification
Application Schedule: State

Existing Permit Data

Existing Permit Number: 10400/R01
Existing Permit Issue Date: 01/16/2018
Existing Permit Expiration Date: 03/31/2023

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2017	---	0.1800	---	0.0500	0.0100	8.65E-05	4.35E-05 [Benzene]

Review Engineer: Joseph Voelker

Review Engineer's Signature: **Date: January 10, 2019**

Comments / Recommendations:
Issue 10400/R02
Permit Issue Date: January 10, 2019
Permit Expiration Date: March 31, 2023

I. Introduction and Purpose of Application

As stated in the application….

NTE Carolinas, LLC (NTE) owns the Kings Mountain Energy Center (KMEC), a natural gas fired combined-cycle power plant, permitted under North Carolina Department of Environmental Quality (NCDEQ Air Quality Permit No. 10400R01. NTE respectfully requests an Air Quality Modification (Minor Permit Change pursuant to 15A NCAC 02Q .0300 to clarify that emission limits for the Combustion Turbine (CT) during startup operations are based on a 3-hour average, as presented in the PSD Permit Application No. 2300386.14A that resulted in the issuance of Air Quality Permit No. 10400R01 (the "Permit Application"). This proposed modification does not result in an increase of the startup event emissions or duration on a per event basis, as described in the Permit Application.

This permit modification will be discussed further in Section III below.

II. Chronology

Date	Description
October 09, 2018	An application was received and assigned application no. 2300383.18B. The application was missing the processing fee. Application was placed on HOLD.
October 22, 2018	Application fee was received. Application was placed IN PROGRESS.
December 13, 2018	Draft sent to Permittee
December 21, 2018	Comments received from Permittee.
January 03, 2019	Revised draft sent to Permittee
January 09, 2019	Permittee responded via email stating "We did receive the draft and are okay with the changes as they were presented…"

III. Modification Description and Regulatory Review

As stated in the application:

This requested clarification is based on the NOx emissions start-up curve, which results in significantly higher NOx emissions rate at the beginning of the startup period and a significantly lower emission rate after the initial period. As an example, ammonia injection to activate the Selective Catalytic Reduction (SCR) is not brought on-line during startups until the CT exhaust reaches a minimum operational temperature. This may take approximately 45-50 minutes to achieve during a cold start-up. Once the SCR is brought on-line, the NOx emissions downstream from the SCR drop significantly and are low for the remainder of the startup event.

The CT at KMEC is designed to achieve the NOx emissions projections during startup on an event basis, not a one-hour average basis, due to the start-up emissions rate being a curve beginning at higher rate and tapering to a lower rate at the end of the startup event. Startup conditions were described in Section 3.1.2 of PSD Permit Application No. 2300386.14A. The duration of the startup events and the total emissions over the full duration of each event are provided in Table 3.2. For example, Table 3.2 indicates that a cold startup event lasting 143.0 minutes, and that worst-case NOx emissions over the duration of a cold startup event total 111 pounds.

Startup emissions limitations are provided in Sections 2.1.A.4.b through 2.1.A.4.d of the current Air Quality Permit for KMEC, Permit No. 10400R01, which is attached hereto as Attachment 3. It appears that the startup emission limits were established by dividing the total emissions per startup event by the duration of the startup event. For example, NOx emissions during a cold startup were given a limit of 46.8 lbs/hour on a 1-hour average, which is approximately equivalent to 111 pounds of NOx over a 143-minute period (i.e., 111 lbs NOx / 143 minutes* 60 minutes/hr= 46.6 lbs/hr).

Based on the discussion above, NTE is requesting a modification to the table in Section 2.1.A.4.d of the Air Quality Permit to clarify that the emissions associated with startup operations are based on a 3-hour average.

This permit engineer agrees with the discussion above for the most part. It is true that a 1-hour average emission rate of 46.8 pounds per hour during a cold start scenario was derived as discussed above. This 46.8 pounds per hour emission rate was used in the NAAQS modeling as a worst-case NOx emission rate for all operating scenarios except "normal operation" "Normal operation" is defined in the permit condition as operation between 50 and 100% maximum load. During normal operation the emission rate used to demonstrate compliance with the NO2 NAAQS was 28.4 lb/hr NO2 (as NOx).

Non-normal operations include all startup scenarios (hot, warm and cold), tuning operations, shutdowns, commissioning. and operation of the combustion turbine below 50% peak load.

Permit condition 2.1 A.4.d reads as follows:

d. The following limits are required in order to demonstrate compliance with the National Ambient Air Quality Standards and the PSD increments as required by 15A NCAC 2D .0530; 40 CFR 51.166(k):

Pollutant	***Emission Rate (lb/hr)***		
	1-hr average	***24-hr average***	***Annual average***
$PM_{2.5}$	*NA*	*19.5 *** *18.2****	*
NO_2	*28.4 [1] *** *46.8[1] ****	*NA*	*
CO	*17.1*** *1486****	*NA*	*NA*

**maximum project impacts were less than the respective SIL in the significant impact analysis*
*** operation during 50 to 100% full load*
**** all other operating scenarios, including start up and shutdown*
[1] lb/hr of NOx

The intent of this permit condition was to memorialize the emission rates used to demonstrate compliance with NAAQS and PSD increments as applicable in the PSD modeling demonstrations. The unit demonstrated compliance when operating from 50 to 100% load at an emission rate of 28.4 lb/hr and in all other operating scenarios ("non-normal" operation) at an emission rate of 46.8 lb/hr as mentioned in the above paragraph. Instead of trying to evaluate an emission rate for each of these different non-normal operating scenarios all of which are relatively infrequent on an annual basis, the modeling approach considered to be conservative for modeling the worst-case emissions was to model the average 1-hour cold start emissions for every hour of the year.

The following table from the original modeling analysis shows that the 46.8 lb/hr emission rate resulted in a maximum impact of 48.42 ug/m3 by itself and in conjunction with ambient background shows a result equal to 171.79 ug/m3 or 91% NAAQS.

Table 3 – Results of Cumulative Modeling – KMEC NO_2 1-hour CT Start-Up Case

NO_2 1-hour NAAQS = 188 μg/m³, BASIS: 8TH-HIGHEST MAX DAILY 1-HR RESULTS AVERAGED OVER 5 YEARS

Case Description	**Modeling Scenario Case No.**	**Model Year**	**Max. Cumulative Impact[1] + Ambient Background[2] (μg/m³)**	**UTM, X (m)**	**UTM Y (m)**	**Max. Project Impact (μg/m³)**	**Model File(s)**
SU+BO+DP	GSU1	-	171.79	471,505	3,897,575	48.42	NO2-1HR-SU-NAAQS11

1. Tier 2 (Ambient Ratio) NOX conversion option (Tier 1/no conversion result multiplied by 0.8)
2. Ambient background based on season and hour-of-day background matrix summarized in Table 2.

Certain assumptions are necessary with respect to modeling a varying emission rate to determine compliance with a 1-hour standard. In the end, it was determined that this 46.8 lb/hr emission rate was conservative. Consult the original modeling analysis for further discussion.

Note that the monitoring imposed elsewhere in 2.1 A.4. with respect to NO2(as NOx) refers to the NSPS KKKK requirements at 2.1 A.3. 2.1 A.4.l reads as follows:

<u>*NOx (and diluent O2)*</u>

l. The Permittee shall meet the monitoring and recordkeeping requirements of condition 2.1.A.3. h through and k. Annual emissions of NOx shall be calculated as the rolling 12-month sum of 1-hour average NOx emissions.

The <u>intent</u> in this condition was that monitoring from the NSPS KKKK condition could be used to readily assess compliance with the primary BACT limit at 2.1 A.4.a and the secondary BACT limits at 2.1 A.4.b and <u>by default</u> would ensure compliance with the limits at 2.1 A.4.d.

In summary, the intent of the conditions above was not for the limit imposed during non-normal operation to be determined on a per hour basis. As such, the permit condition as written is incorrect and is not consistent with the original intent. To resolve the issue a brief discussion would be useful to first understand how the available CEM data is used to assess compliance with the NSPS KKKK standards and then how it can be extended to determine compliance with the PSD emission limits in a consistent manner.

<u>NSPS KKKK</u>

The emission limits required under NSPS KKKK are imposed in the permit at 2.1 A.3.b as follows:

b. The following NOx emission limitations for the combustion turbine (ID No. ES-1) shall not be exceeded, except during startup, shutdowns, and malfunction.
   i. 15 ppm at 15 percent O2 or,
   ii. 96 ppm at 15 percent O2 when operating at less than 75 percent of peak load [§60.4320]

The permittee has also chosen to utilize CEMS (NOx and O2 monitors) to determine compliance with these limits. Note however, that there are two “emission limit” scenarios, one at 75% peak load and above, and one below 75% peak load. NSPS requires the Permittee to calculate emissions on an hourly basis but evaluates compliance on a 30-day rolling average basis. (Ultimately, excess emissions as defined under NSPS during startup shutdown and malfunction are not violations of these emission limitations. However, this is beyond the scope of the discussion here).

It is obvious for any given operating hour that occurs completely under one operating scenario which standard applies. But consider what happens in the hours that straddle these operating scenarios.

49 CFR 60.4380(b)(3) states:

> *For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.*

So, for an operating hour that straddles the 75% peak load threshold for ANY length of time, the less than 75% peak load standard, which is the highest emissions standard, or least stringent standard, applies.

<u>PSD</u>

To address the concern of the Permittee regarding the 1-hour averaging time during non-normal operation, permit condition 2.1.A 4.d will be revised as shown below.

d. The following limits are required in order to demonstrate compliance with the National Ambient Air Quality Standards and the PSD increments as required by 15A NCAC 2D .0530; 40 CFR 51.166(k):

Pollutant		***Emission Rate (lb/hr)***		
	1-hr average	***<u>3-hr contiguous rolling average</u>***	***24-hr average***	***Annual average***
$PM_{2.5}$	*NA*	***<u>NA</u>***	*19.5 ** 18.2****	***
NO_2	*28.4 [1] ***	***<u>46.8 [1] ++</u>***	*NA*	***
CO	*17.1***	***<u>1,486 ++</u>***	*NA*	*NA*

**maximum project impacts were less than the respective SIL in the significant impact analysis*
*<u>** applicable when operating for a full operating hour</u> during 50 to 100% full load*
**** all other operating scenarios, including start up and shutdown*
<u>++ applicable under all operating scenarios</u>
[1] lb/hr of NOx

As discussed above, under NSPS KKKK, the source is subject to the least stringent emissions standard for the entire hour if the source is operated under the operating scenario for any fraction of that given hour. To stay consistent with the NSPS monitoring, recordkeeping and reporting requirements as much as possible, the permit condition is being clarified to note that the most stringent limitation (i.e., the normal operation emission limitation) of 28.4 lb/hr is only

applicable when operating for a full operating hour under 50 to 100% full load

When the source is operated for any amount of time in a given hour under non-normal operations, the 28.4 lb/hr rate will not apply.

To address the averaging time issue for the non-normal emission limit of 46.8 lb/hr on a 1-hour average, the condition is being revised to apply a 3-hour contiguous rolling average emission rate, that applies at all times, of 46.8 pounds per hour.

The Permitee had requested a 3-hour average value of 46.8 lb/hr that was exclusive of the time period when the normal operating limit applied. However, it was determined this would not be practical given the NSPS monitoring approach and the fact that not all of the non-normal operating scenarios will take a full three hours. For example, this emission limit also applies in any hour of operation in which the operating load drops below 50% of maximum load, which can be unpredictable. Thus, recordkeeping for the determination of compliance with this 3-hour average for time periods that were exclusive of time periods of operation at or above 50% of maximum load would be problematic.

In consultation with the permittee it was decided that the simplest approach was to allow for a 3-hour contiguous rolling average emission limit of 46.8 lb/hr of NOx that applies during all operating scenarios. In context of NSPS CEMS monitoring and operation, which is the basis of the monitoring approach here, a 3-hour rolling average implies when you “add an hour, you drop an hour.” Thus, a rolling 3-hour average could be separated by many hours of non-operation which would not be representative of the operating scenarios modeled. By specifying a contiguous rolling average, a cold start scenario will not have to “reach back” to a shutdown scenario to continue calculation.

As mentioned above the 46.8 lb/hr emission limit was modeled over every hour of the year. The secondary BACT limit at Section 2.1 A.4.b and c states:

Secondary BACT Limitations to include start up and shutdown, commissioning and tuning operations

b. *The BACT permitted emission limits for the emission source (ID No. ES-1), during start up, shutdown, commissioning, tuning and normal operations, are as follows:*

Table 4b.

Regulated Pollutant	*BACT Limits, tons per 12 months, rolling basis*
$PM_{10}/PM_{2.5}$	*65.4*
NO_x	*103.4*
CO	*243.2*
VOC	*86.9*
GHGs	*1,676,538 TPY of GHG on a* CO_2e *basis*

c. *The Permittee shall:*
   i. *limit operation during start up and shut down operations to 500 hours per year (rolling 12-month basis);*
   ii. *minimize operation during commissioning to the maximum extent possible;*
   iii. *limit tuning operations to 2 events per year (rolling 12-month basis). Each event shall not exceed 8 hours; and;*
   iv. *minimize emissions to the maximum extent possible during start up shutdown, commissioning and tuning operations.*

So, the secondary BACT limit effectively limits hours of operation of the source to 516 hours per year under scenarios that are subject to this emission rate, which equates to approximately 12 tpy of the 103 tpy total emission rate.

Carbon monoxide CO

The Permittee has also proposed a clarification regarding the 1-hour CO emission rate of 1,486 lb/hr. For the same arguments made above the non-normal CO emission rate limit will also be revised to a contiguous rolling 3-hour average that applies during all operating scenarios.

Note for both CO and NOx, no changes are being made to the monitoring conditions and operating limitations. It was and still is expected that monitoring and operational limits imposed for the PSD BACT limits will be sufficient to ensure the NAAQS and or increments will not be exceeded.

IV. NSPS, NESHAPS, PSD, Toxics, Attainment Status, 112(r), and CAM

NSPS
Relevant NSPS applicability is discussed in Section III.

NESHAP/MACT
The facility is a minor source of HAP.

PSD
Cleveland County is in attainment for all pollutants. The facility is a PSD major source. Relevant PSD applicability is discussed in Section III.

CAM
CAM will be addressed during the initial TV permitting process.

112r
The Permittee is not subject to Section 112(r) of the Clean Air Act requirements because of the following explanation as provided in the original application:

> NTE is proposing to use a dilute (19 percent by weight) solution of aqueous ammonia for the SCR NOx control system in lieu of anhydrous or higher concentration aqueous ammonia solutions, which are regulated under RMP if used or stored in amounts greater than 10,000 pounds (anhydrous ammonia) or 20,000 pounds (aqueous ammonia in concentrations of 20 percent or greater). Therefore, the RMP regulations will not be applicable to the Project.

Toxics
The proposed changes will result in a change in TAP emissions. No modeling review is necessary.

V. Compliance History

The facility is under construction and has not commenced operation.

VI. Changes Implemented in Revised Permit

~~Existing Condition No.~~	~~New Condition No.~~	~~Changes~~
Cover Letter	Cover Letter	• Used current shell language, updated permit numbers, dates, etc. •
Permit page one	Same	• Revised dates, permit numbers, etc. using current shell standards •
2.1 A.4.d	same	• Added a 3-hr contiguous rolling average column for the non-normal operating limits for NO2 (as NOx) and CO • Added a footnote to clarify the normal operating limit applied only during a full operating hour during 50 to 100% full load • Added a footnote to indicate that the 3-hour rolling averages were applicable under all operating scenarios
Section 3 General Conditions	Same	• To condition 17, added the following language consistent with the current 02Q .0300 permit shell *Additionally, in accordance with 15A NCAC 2D .0605, the permittee shall follow the procedures for obtaining any required audit sample and reporting those results.*

VII. Public Notice/EPA and Affected State(s) Review

Not applicable.

VIII. Recommendations

Issue permit no. 10400R02.

Attachment D

Permit Review for Permit No. 10400R03
(Application No. 2300383.19A)

NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: **August 12, 2019**

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300383
Inspector's Name: Bob Caudle
Date of Last Inspection: 10/02/2018
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Kings Mountain Energy Center

Facility Address:
Kings Mountain Energy Center
181 Gage Road
Kings Mountain, NC 28086

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

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

Permit Applicability (this application only)

SIP: yes
NSPS:
NESHAP:
PSD: yes
PSD Avoidance:
NC Toxics: yes
112(r):
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Jim Medford Project Manager (704) 259-7915 181 Gage Road Kings Mountain, NC 28086	Michael Green Vice President (904) 687-1857 24 Cathedral Place, Suite 300 St. Augustine, FL 32084	Matthew Hickey EHS Manager (410) 459-9594 181 Gage Road Kings Mountain, NC 28086

Application Data

Application Number: 2300383.19A
Date Received: 05/31/2019
Application Type: Modification
Application Schedule: State

Existing Permit Data
Existing Permit Number: 10400/R02
Existing Permit Issue Date: 01/10/2019
Existing Permit Expiration Date: 03/31/2023

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2017	---	0.1800	---	0.0500	0.0100	8.65E-05	4.35E-05 [Benzene]

Review Engineer: Joseph Voelker

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

Comments / Recommendations:
Issue 10400/R03
Permit Issue Date: 08/12/2019
Permit Expiration Date: 03/31/2012

I. Introduction and Purpose of Application

As stated in the application….

NTE Carolinas, LLC (NTE) is submitting this permit application to modify certain condition in the Kings Mountain Energy Center's (KMEC) operating permit pertaining to ammonia emissions.

First, the facility is requesting removal of an emission limit that was erroneously established as Best Available Control Technology in the Prevention of Significant Deterioration (PSD) permit issued for initial construction and operation of the KMEC facility.

Second, NTE is requesting an increase in the permitted allowable emission rate for ammonia associated with compliance with the North Carolina toxic air pollutant (TAP) regulations.

This permit modification will be discussed further in Section III below.

II. Chronology

Date	Description
May 31, 2019	An application was received and assigned application no. 2300383.19A. The application was missing the processing fee. Application was placed on HOLD.
July 23, 2019	Application fee was received. Application was placed IN PROGRESS.
August 1, 2019	Draft sent to Permittee
August 9, 2019	Permittee sent an email stating " we are good with the permit update."

III. Modification Description and Regulatory Review

Removal of Ammonia BACT Limit

As stated in the application….

As discussed with Mr. Joe Voelker on December 6, 2018, the PSD permit issued for the project inadvertently included a BACT limit for ammonia. Ammonia is not a regulated pollutant under the PSD regulations, nor is it recognized as a precursor for PM2.5 under the North Carolina state implementation plan (SIP). Accordingly, NTE requests removal of the ppm Ammonia limit in Section 2.1.A.4.a and the associated monitoring requirement in Section 2.1 A.4.m.

This review engineer agrees that under NCs PSD implementing regulation 15A NCAC 02D .0530, ammonia is not a regulated pollutant nor is it considered a precursor for PM 2.5. As such, the ammonia BACT limit on the combustion turbine (CT) and duct burner (DB) may be removed from the permit without subjecting the removal to public or EPA review procedures under 02D .0530.

However, the NOx BACT emission limit of 2 ppmvd @ 15% O_2, 1-hr basis is achieved by:
i) exclusive natural gas firing,
ii) Dry low NOx combustors on the CT and
iii) SCR on the CT and DB exhaust.

The ammonia injection is part of the SCR control system. To ensure proper operation and maintenance of a SCR system, NC routinely employs ammonia slip emission limits. A prime example is the PSD permit issued for the following facility:

NTE Carolinas II, LLC – Reidsville Energy Center"
Air Quality Permit No. 10494R00 issued July 14, 2017
Facility ID: 7900182

Reidsville, North Carolina
Rockingham County

That permit contains the following monitoring requirement **for NOx** at Section 2.1 A.5.n

n. The Permittee shall install, certify, operate and maintain a second NOx CEMS with an NH_3/NO converter to monitor the Ammonia slip, which shall be limited to 5 ppm, via the differential NOx/NH_3 converter method. The Permittee shall meet the monitoring and recordkeeping requirements of Section 2.1 A.3.h through k.

Note that this monitoring is the same in the current Kings Mountain permit **for the ammonia BACT limit** found at Section 2.1 A.4.m. Thus, in the end the DAQ will remove the ammonia slip limit as a BACT limit but it will remain as a monitoring requirement for the NOx control system.

Request to raise ammonia slip limit from 5 to 10 ppmvd

Since the ammonia slip monitoring requirement is now to be used to ensure proper operation and maintenance of the SCR control system for NOx, the permittee has requested to raise the slip limit from 5 to 10 ppmvd.

Via emails dated June 20 and July 3, 2019 (included as attachments to this review document), the Permittee has justified that increasing the ammonia slip to 10 ppmvd can still be used to ensure proper operation of the NOx control system. Some justifications are as follows (excerpted directly from the referenced emails):

- Unit tuning transients, our Combustion Turbine tuning system is complex and if any part of it lags due to load changes, ambient changes and etc. then this can spike our NH3 to as high as 8 ppm or 9 ppm for a moment and with the one hour limit we do not have sufficient time to bring this down below the 5 ppm limit.
- Higher mass flow through the Unit during the winter which increases the transfer efficiency needed at the catalyst, which means even less room for anything to operate less than perfect.
- Slight and normal buildup of debris or insulation on the Catalyst over long run periods, a catalyst is cleaned on average every two years. We have had to clean KMEC's catalyst three times within one year to avoid this issue. While we maintain our permit limits during these cycles, the act of shutting down and starting up for these cleanings result in more overall emissions than the NH3 exceedances would have if we didn't.
- The performance of the SCR is monitored not only by ammonia slip, but there are several other important process parameters being monitored on a continuous basis, such as temperature of the catalyst to ensure proper operation, ammonia flow rate, and catalyst differential pressure. In addition, the system is subject to a rigorous inspection and maintenance program that includes evaluation of catalyst life/activity during maintenance turnaround events. In addition, if the system is not properly operating increasing the ammonia addition rate (which increases slip) contributes to increased operating costs, so KMEC already has a vested interest in minimizing ammonia injection rate.

Considering the information supplied by the Permittee, the DAQ finds it reasonable to increase the allowable ammonia slip limit from 5 to 10 ppmvd @ 15% O2 o a 1-hr basis.

Implications with NC Air Toxics Rules (15A NCAC 02D .1100)

The Permittee estimated that at the current 5 ppmvd @ 15%O2 ammonia slip limit, the maximum ammonia emissions from the CT stack would be 25.9 lb/hr. This rate was modeled in the original PSD application and resulted in an ambient impact of 27.4 ug/m3, compared to the acceptable ambient level (AAL) of 2700 ug/m3 on a one hour averaging basis. In other words, 5 ppmvd ammonia slip at the maximum operation rate of the CT is expected to result in impacts on the order of 1% of the AAL. Holding the dispersion parameters constant, the ambient impacts are directly proportional to the pollutant emission rate. Thus, doubling the allowable slip to 10 ppmvd, or approximately 54 lb/hr, at the maximum operation rate of the CT would be expected to result in ambient impacts twice as high or on the order of 2% of the AAL. It is clear then that allowing an increase in the ammonia slip concentration to 10 ppmvd will not cause any compliance issues with the ammonia AAL.

To simplify any potential secondary compliance issues with 02D .1100, the permittee has requested to increase the permitted allowable ammonia emission rate under 02D. 1100 to the rate that would result in an ambient impact that is

95% of the ammonia AAL. Extrapolating 5 ppmvd, or 25.9 lb/hr, at an impact of 27.4 ug/m3 to an impact of 2565 ug/m3 (i.e., 0.95* 2700 ug/m3) yields an allowable ammonia emission limit of approximately 2,400 lb/hr. Thus, the Permittee would have to exceed the ammonia slip monitoring limit under 02D .0530 by a factor of approximately 94 before the ammonia emissions would even approach the ammonia AAL. The DAQ finds this approach acceptable. The permit will be revised accordingly.

IV. NSPS, NESHAPS, PSD, Toxics, Attainment Status, 112(r), and CAM

NSPS
This change to the ammonia slip allowance is not expected to result in any compliance issues with respect to any applicable NSPS regulations namely, NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines.

NESHAP/MACT
The facility is a minor source of HAP.

PSD
Cleveland County is in attainment for all pollutants. The facility is a PSD major source. Relevant PSD applicability is discussed in Section III.

CAM
CAM will be addressed during the initial TV permitting process.

112r
The Permittee is not subject to Section 112(r) of the Clean Air Act requirements because of the following explanation as provided in the original application:

> NTE is proposing to use a dilute (19 percent by weight) solution of aqueous ammonia for the SCR NOx control system in lieu of anhydrous or higher concentration aqueous ammonia solutions, which are regulated under RMP if used or stored in amounts greater than 10,000 pounds (anhydrous ammonia) or 20,000 pounds (aqueous ammonia in concentrations of 20 percent or greater). Therefore, the RMP regulations will not be applicable to the Project.

Toxics
See Section III above for discussion of implications with respect to 02D .1100. No modeling review is necessary.

V. Compliance History

Based on the most recent compliance inspection dated 10/2/2018, the facility notified MRO of initial startup on January 10, 2018. The inspector made the following statement in the report:

> "Based on my observations during this inspection, this facility appeared to be in compliance with the applicable air quality regulations."

VI. Changes Implemented in Revised Permit

Existing Condition No.	New Condition No.	Changes
Cover Letter	Cover Letter	• Used current shell language, updated permit numbers, dates, etc.
Permit page one	Same	• Revised dates, permit numbers, etc. using current shell standards
2.1 A,4	Same	02D .0530 condition
Table 4.a	Same	• Removed ammonia BACT limit
m	Same	• Removed the phrase “Ammonia, NH3”; the condition is now indicated to be monitoring for “NOx and diluent O2” • Added the phrase “which shall be limited to 10 ppmv @ 15% O2, 1 hr basis”
2.2 A.1.a	Same	• Revised ammonia emission limit ID No. ES-1 from 25.9 to 2,400 lb/hr

VII. Public Notice/EPA and Affected State(s) Review

Not applicable.

VIII. Recommendations

Issue permit no. 10400R03.