NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: TBD

Region: Mooresville Regional Office
County: Lincoln
NC Facility ID: 5500082
Inspector's Name: Emily Supple
Date of Last Inspection: 08/05/2020
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Corporation LCTS

Facility Address:
Duke Energy Corporation LCTS
6769 Old Plank Road - SR 1511
Stanley, NC 28164

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: .0521, .0524, .0530, .0544, .0614, .1111, .1418
02Q: .0317, .0400, .0504
NSPS: 02D .0524 (Subparts GG, KKKK, TTTT)
NESHAP: 02D .1111 (Subparts YYYY, ZZZZ)
PSD: 02D .0530, 02D .0544
PSD Avoidance: 02Q .0317
NC Toxics: n/a
112(r): n/a
Other: Cross State Air Pollution Rule

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Benjamin Loveland Senior EHS Professional (704) 742-3000 6769 Old Plank Road Stanley, NC 28164	Kristopher Eisenrieth General Manager II (704) 630-3015 1555 Dukeville Road Salisbury, NC 28146	Erin Wallace Lead Environmental Specialist (919) 546-5797 410 South Wilmington Street NCRH-15 Raleigh, NC 27601

Application Data

Application Number: 5500082.20A, .20B, .21A
Date Received: 10/08/20 (.20A),10/23/20 (.20B), 03/29/21 (.21A)
Application Type: Renewal/Modification
Application Schedule: TV-Renewal

Existing Permit Data

Existing Permit Number: 07171/T13
Existing Permit Issue Date: 02/06/2020
Existing Permit Expiration Date: 04/30/2021

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2019	0.0100	18.03	1.43	6.80	1.46	0.1783	0.1489 [Formaldehyde]
2018	5.69	96.06	1.79	31.91	5.50	0.6158	0.2735 [Formaldehyde]
2017	0.6200	14.63	1.34	5.31	1.15	0.1309	0.1181 [Formaldehyde]
2016	2.10	39.01	1.59	22.31	2.80	0.3306	0.2130 [Formaldehyde]
2015	2.70	40.31	1.63	23.26	2.84	0.3299	0.2245 [Formaldehyde]

Review Engineer: Russell Braswell

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

Comments / Recommendations:
Issue 07171/T14
Permit Issue Date: TBD
Permit Expiration Date: TBD+5 years

1. Purpose of Applications:

a. 5500082.20A (received October 8, 2020)

Duke Energy Corporation LCTS (DEC; the facility) currently operates a power plant in Lincoln County under Title V permit 07171T13 (the existing permit). The existing permit expired on April 30, 2021. Before the existing permit expired, DEC submitted this application in order to renew the Title V permit.

Because the renewal application was received at least six months before the expiration date, the existing permit will remain in effect, regardless of expiration date, until the renewed permit is issued.

In addition to renewing the permit, DEC requested clarifications regarding PSD monitoring language in the existing permit. This is discussed in Section 6.c below.

b. 5500082.20B (received October 23, 2020)

The existing permit includes a reference to the facility's Title IV permit (a.k.a. acid rain permit). The acid rain permit is set to expire at the same time as the Title V permit. Therefore, DEC has submitted application .20B in order to renew the acid rain permit. In this application, DEC specifically requested that the Title IV and Title V permits be renewed at the same time to allow for an easier renewal process in the future.

c. 5500082.21A (received March 29, 2021)

The existing permit includes Specific Condition 2.2 A.2, which requires DEC to submit a new permit application within 12 months of beginning operation of the turbine ES-19. DEC was required to submit this application because ES-19 was added to the permit as a 2-step significant modification as allowed by 15A NCAC 02Q .0501(b)(2). The application suggested minor corrections to the Title V permit but stated that no substantial changes have been made to the ES-19 turbine since it was initially added to the permit.[1]

DEC's requirements under 15A NCAC 02Q .0501(b)(2), 15A NCAC 02Q .0504, and Specific Condition 2.2 A.2 of the existing permit are discussed in Section 6.j.v below.

2. Facility Description:

This facility is a power plant that consists of 16 simple cycle turbines (ES-1 through 16) and one developmental simple cycle turbine (ES-19). Each of the turbines can be fired with natural gas or No. 2 fuel oil. In addition, the facility includes emission sources that support the turbines, such as fuel tanks and fire protection systems. The facility is generally used to produce electricity for sale to the grid during periods of peak demand.

The turbines ES-1 through 16 have been in operation since before 2000 and have a nominal combined capacity of 1,488 megawatts.

The turbine ES-19 is being used for research and development. The planned development cycle involves three stages (A, B, and C) and then operation once development is completed. While under development, the turbine is operated by the Siemens Energy company, but is still producing electricity that DEC sells on

[1] Email from Erin Wallace on March 29, 2021.

the power grid. Development on ES-19 is expected to continue through 2024. At that time, DEC will assume control of the turbine, and the turbine's nominal output is expected to be 402 megawatts.[2]

3. Title V Permit Modifications Following the Previous Permit Renewal:

- May 19, 2016 — Permit T10 issued. This action renewed the Title V and Title IV permits and made minor corrections throughout the document.
- June 20, 2018 — Permit T11 issued. This action was a PSD major modification that added a new combustion turbine (ID No. ES-19) and supporting activities.
- September 24, 2019 — Permit T12 issued. This action was an administrative amendment that corrected references to excess emissions from the new turbine during startup and shutdown during the new turbine's developmental phase.
- February 6, 2020 — Permit T13 issued. This action was a significant modification to incorporate the new turbine into the Title IV acid rain permit.

4. Application Chronology:

- October 8, 2020 — Application .20A received.
- October 23, 2020 — Application .20B received.
- January 21, 2021 — Applications transferred to Russell Braswell.
- February 10, 2021 — An internal draft of the permit and review were sent to DAQ's Permit Section Chief (Mark Cuilla) and DAQ's Stationary Source Compliance Branch (Samir Parekh). For a summary of comments received, see Section 9.
- March 29, 2021 — Application .21A received.
- March 29, 2021 — Email to Erin Wallace regarding application .21A. She responded by email later that day.
- April 5, 2021 — An updated draft of the permit and review were sent to DAQ's Mooresville Regional Office (Bruce Ingle, Jennifer Womick, Emily Supple) and DEC staff (Erin Wallace, Kris Eisenrieth). For a summary of comments received, see Section 9.
- June 3, 2021 — Conference call between DAQ and DEC to discuss changes included in the draft permit.
- August 3, 2021 — Additional conference call between DAQ and DEC to discuss changes included in the draft permit.

[2] See the application review for Title V permit 07171T11, issued June 20, 2018 (pages 6 and 7).

- October 1, 2021 — After discussions with DAQ and DEC staff, DEC accepted changes to the CAM plan proposed in the draft permit. See Section 6.d for a discussion of CAM plan requirements and changes.
- XXXX — The Public Notice and EPA review periods began.
- XXXX — The Public Notice period ended.
- XXXX — The EPA Review period ended.
- XXXX — Permit issued.

5. Changes to the Existing Permit:

Page No(s).*	Section*	Changes
Throughout	Throughout	• Updated dates/permit numbers. • Fixed formatting. • Corrected typos. • Removed references to 02Q .0504 because the Permittee has completed this requirement. • Removed references to 40 CFR Part 97, Subpart BBBBB because this rule no longer applies. Subparts AAAAA and CCCCC still apply.
3	1.	• Removed references to 02Q .0501 additional applications because the Permittee has completed this requirement.
9	2.1 A.4	• Corrected the following issues with the CAM plan: o Changed the averaging period to hourly (was 4-hour block) in order to match the limit in NSPS Subpart GG. o Going below the accepted water-to-fuel ratio is an exceedance of NSPS Subpart GG because that rule defines excess emissions as periods where the water-to-fuel ratio is less than the tested value. Therefore, periods below the tested water-to-fuel ratio are exceedances, not excursions. Removed the QIP threshold because this CAM plan defines excursions and requires reporting of all excess emissions.
17	2.1 C.5	• Broke up former paragraph 2.1 C.5.a into subparagraphs for clarity. This change does not reflect a change in the Permittee's compliance requirements. • Clarified that the "ozone season" is May 1 to September 30 of each year.
n/a	2.1 C.6 (former)	• Removed the requirement to submit an updated acid rain permit application because the applicant has completed this requirement.

Page No(s).*	Section*	Changes
19	2.2 A.1	• Added clarification for "full load equivalent hours" as requested by the application. • Added requirement for NOx CEMS data substitution when demonstrating compliance with 15A NCAC 02D .0530. • Added information about cylinder gas audits and relative accuracy test audits for CO CEMS as requested by the Permittee. • Added requirement for CO CEMS data substitution when demonstrating compliance with 15A NCAC 02D .0530. • Added requirement for CO_2 CEMS data substitution when demonstrating compliance with 15A NCAC 02D .0530. • Added limit and definition of monitor downtime for CEMS. • Clarified that records of excess emissions and monitor downtime must be submitted in a format approved by DAQ. • Changed the time limit for submitting performance test results to 30 days (previously 60). Note that 30 days is the standard time limit, but General Condition JJ allows for the facility to request an extension. • Renumbered paragraphs to reflect above changes. • Removed references to steam from this condition because ES-19 does not use water or steam injection.
n/a	2.2 A.2 (former)	• Removed this section because the Permittee has completed all requirements under 02Q .0504.
27	3.	• Updated General Conditions to v5.5.

* This refers to the current permit unless otherwise stated.

6. Regulatory Overview and Rules Review:

Under the existing permit, DEC is subject to the following State Implementation Plan (SIP) rules:

- 15A NCAC 02D .0521 "Control of Visible Emissions"
- 15A NCAC 02D .0524 "New Source Performance Standards" (40 CFR Part 60, Subparts GG, KKKK, and TTTT)
- 15A NCAC 02D .0530 "Prevention of Significant Deterioration"
- 15A NCAC 02D .0544 "Prevention of Significant Deterioration Requirements for Greenhouse Gases"
- 15A NCAC 02D .0614 "Compliance Assurance Monitoring"
- 15A NCAC 02D .1111 "Maximum Achievable Control Technology" (40 CFR Part 63, Subparts YYYY and ZZZZ)
- 15A NCAC 02D .1418 "New Electric Generating Units, Large Boilers, and Large I/C Engines"
- 15A NCAC 02Q .0317 "Avoidance Conditions" (Avoidance of PSD)
- 15A NCAC 02Q .0400 "Acid Rain Procedures"
- 15A NCAC 02Q .0504 "Option for Obtaining Construction and Operation Permit"

In addition to the above SIP rules, DEC is also subject to the Cross State Air Pollution Rule. This rule is not included in North Carolina's SIP. DEC's requirements under each of these rules are discussed below. In addition, a discussion of several non-applicable rules is also included below.

a. 15A NCAC 02D 0521 "Control of Visible Emissions"

This rule limits the opacity of non-fugitive visible emissions (VE) from emission sources that do not have a specific VE limit under other 02D .0500 rules. For sources constructed after 1971 (i.e., each turbine at this facility), the rule limits opacity in most cases to 20%. Each turbine at this facility is subject to this rule. The two fuel oil storage tanks (ID Nos. ES-17 and 18) are not subject to this rule because they do not produce visible emissions.

In general, burning natural gas in a combustion turbine is not expected to produce VE in excess of 20% under normal operations. To address the possibility of VE from the turbines while burning fuel oil, DEC is required to perform a Method 9 test for VE after operating for 1,100 hours on fuel oil. An additional test is required for each subsequent 1,100 hours of operation. DEC is required to keep records of VE tests and report them twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

b. 15A NCAC 02D .0524 "New Source Performance Standards" (NSPS; 40 CFR Part 60)

This rule incorporates the NSPS rules into North Carolina's SIP (excluding those rules listed in 02D .0524(b)). NSPS Subparts GG, KKKK, and TTTT apply to sources at this facility.

i. NSPS Subpart GG "Standards of Performance for Stationary Gas Turbines"

This rule applies to stationary gas turbines constructed after October 3, 1977 but that are also not subject to NSPS Subpart KKKK. The sixteen simple cycle turbines (ID Nos. ES-1 through 16) are subject to this rule.

In general, the rule requires that turbines comply with emission standards for nitrogen oxides (NOx) and sulfur dioxide (SO_2).

In order to comply with the NOx limit, DEC uses water injection in the turbines which reduces combustion temperature, thereby reducing NOx generation. In order to comply with the SO_2 limit, DEC monitors the sulfur content of all fuels in the turbines to ensure that actual SO_2 emissions do not exceed the limit.

In order to demonstrate compliance with the rule, DEC must operate a continuous monitor for the water-to-fuel ratio on each turbine. DEC must keep records of fuel sulfur content and the monitor output. Reports of the recordkeeping activities must be submitted twice per year.

The permit also includes an Alternative Operating Scenario which allows DEC to operate these turbines without water injection during periods of "catastrophic" power loss.

Based on the most recent inspection, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

ii. NSPS Subpart KKKK "Standards of Performance for Stationary Combustion Turbines "

This rule applies to stationary gas turbines constructed, modified, or reconstructed after February 18, 2005. The new turbine (ES-19) is subject to this rule. All other turbines at this facility were constructed before this date and have not been modified/reconstructed after this date.

In general, this rule limits emissions of NOx and sulfur dioxide SO_2 based on the type of fuel being fired. However, per §60.4310(b), turbines used for research and development are not subject to NOx limits under this rule. DAQ has previously determined that while ES-19 is in the developmental stages A, B, and C, this turbine will be exempt per §60.4310(b).[3] ES-19 is still in the developmental stages, so the NOx limit does not apply under this rule at this time.

Note that, in addition to other requirements under NSPS Subpart KKKK, the permit requires DEC to submit a permit application before the conclusion of development in order to fully incorporate the requirements of this rule into the permit.

In order to demonstrate compliance with the SO_2 limit, DEC must not burn any fuel with an expected SO_2 emission rate that exceeds 0.06 pounds per million Btu. In addition, DEC must perform an annual emission test or monitor fuel sulfur content per §§60.4415, 60.4360 or 60.4365.

DEC must keep records of monitoring activities, excess emissions, and monitor downtime. These records must be reported twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

iii. NSPS Subpart TTTT "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units"

This rule applies to stationary gas turbines that commenced construction after January 8, 2014 or reconstruction after June 18, 2014. The new turbine (ES-19) is subject to this rule. All other turbines at this facility were constructed before this date and have not been modified/reconstructed after this date.

In general, this rule limits emissions of carbon dioxide (CO_2) from the turbine as a function of heat input and net-electric sales. In order to demonstrate compliance, DEC must keep records of fuel usage and follow all requirements of 40 CFR Part 75, Subpart F.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

c. 15A NCAC 02D .0530 "Prevention of Significant Deterioration" ("PSD"; 40 CFR Parts 51 and 70), and 15A NCAC 02D .0544 "Prevention of Significant Deterioration Requirements for Greenhouse Gases"

This facility is considered a major source for PSD and has undergone multiple major modifications for PSD. As a result, the permit includes Best Available Control Technology (BACT) short-term and long-term emission limits for all permitted emission sources. Table 1 summarizes the BACT requirements and when they were included in the permit.

[3] Letter from William Willets, Chief, Permitting Section, Division of Air Quality, NCDEQ, to Michael Brissie, Station Manager, Duke Energy Corporation LCTS, June 8, 2017.

Table 1: Summary of BACT requirements

Emission Sources	Pollutants	Requirements	Notes
Turbines (ES-1 through 16)	NOx, SO_2, CO, VOC, PM, H_2SO_4, Pb	• Short-term emission standards based on fuel; • Annual emission limits; • Limit sulfur and nitrogen content of fuel oil; • Fuel oil to be supplied by only one of the two tanks at any given time. • Less than 32,000 hours operation for all sixteen turbines per calendar year; • Less than 2,500 hours operation per turbine per calendar year; and • Semiannual reporting.	• Included in the Title V permit as of the R03 revision (issued February 12, 2002), which is the beginning of DAQ's electronic record of this permit.
Tanks (ES-17,18)	VOC	• Annual emission limit, but the PSD limits associated with ES-1 through 16 are assumed to be sufficient to demonstrate compliance for the oil storage tanks.	• Included in the Title V permit as of the R03 revision.
Turbine (ES-19) and Tank (ES-20)	CO, VOC, NOx, PM, GHG	• Short-term emission standards; • Operate an oxidation catalyst and catalytic reduction; • Limit fuel sulfur content; • Limit fuel oil throughput; • Emission testing for Version A and post-development; • Monitor CO and NOx with CEMS. • Monitor GHG with CEMS or NSPS Subpart TTTT; • Monitor ammonia injection rate and catalyst inlet temperature; • Less than 4,677 hours of full-load equivalent operation per calendar year; • Reporting twice per year; and • Submit design data prior to commencing operation of Version A, and any subsequent changes as needed.	• First added to the permit with the Title V permit with the T11 revision (issued June 20, 2018).

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued Compliance will be determined with subsequent inspections and reports. In addition, compliance with the requirement to submit final design data for ES-19 will be evaluated when that report is received.

DAQ has previously determined that data substitution should be required when using a CEMS to demonstrate compliance with long-term emission limits. DEC is using a CEMS to demonstrate compliance with NOx and carbon monoxide (CO) emission limits, and has the option to use CEMS for the GHG limit, so data substitution should be addressed for these pollutants.

- For GHG and NOx, the permit will be updated to require the data substitution procedure in 40 CFR Part 75, Subpart D. Note that this facility is holds an acid rain permit (see Section 6.h below), and the GHG and NOx CEMS are already subject to this data substitution procedure.
- For CO, the permit will be updated to require the facility to substitute missing hourly data with the highest recorded emission data from the previous 2,160 hours of operation.[4]

In addition to the above, the specific condition for PSD in the permit will be updated to allow for a maximum of 5% monitor downtime. These changes are for compliance purposes only and will not impact actual or potential emissions from the facility.

In addition to the above, in the application for permit renewal DEC suggested two changes to the monitoring requirements for ES-19. The first change regards clarifying the facility's requirements regarding for performing regular cylinder gas audits and relative accuracy test audits while operating the CO CEMS. The second change clarifies the limit of full load equivalent hours of operation. Both of DEC's suggested changes have been included in the permit. These changes are not expected to impact actual or potential emissions from the facility.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

d. 15A NCAC 02D .0614 "Compliance Assurance Monitoring" (CAM; 40 CFR Part 64)

The compliance assurance monitoring (CAM) rule requires owners and operators to conduct monitoring to provide a reasonable assurance of compliance with applicable requirements under the act. Monitoring focuses on emissions units that rely on pollution control device equipment to achieve compliance with applicable standards. An emission unit is subject to CAM, under 40 CFR Part 64, if all of the following three conditions are met:

I. The unit is subject to any (non-exempt, e.g., pre-November 15, 1990, Section 111 or 112 standard) emission limitation or standard for the applicable regulated pollutant.
II. The unit uses any control device to achieve compliance with any such emission limitation or standard.
III. The unit's pre-control potential emission rate exceeds 100 percent of the amount required for a source to be classified as a major source; i.e., either 100 tpy (for criteria pollutants) or 10 tpy of any individual/25 tpy of any combination of HAP.

Table 2 compares each control device at this facility to the above criteria:

[4] This is similar to the general data substitution procedure in 40 CFR Part 75, but that Part only specifically references GHG, NOx, and SO_2. Therefore, the permit can reference this procedure for those pollutants, but an alternative method must be specified for CO.

Table 2: CAM analysis

Control Device	Associated Emission Sources	Emission Limit / Rule	Triggers CAM?	Notes
Selective catalytic reduction and oxidation catalyst, controlling NOx and CO	Turbine (ES-19)	02D .0524 (NSPS Subpart KKKK)	No	1
		02D .0530 (PSD)	No	
		02D .1418 (RACT)	No	
		02Q .0400 (Acid Rain Permit)	No	2
		40 CFR Part 97 (CSAPR)	No	3
Water injection systems, controlling NOx	Turbines (ES-1 through 16)	02D .0524 (NSPS Subpart GG)	Yes	4
		02D .0530 (PSD)		
		02Q .0317 (PSD Avoidance)	No	5
		02Q .0400 (Acid Rain Permit)	No	2
		40 CFR Part 97 (CSAPR)	No	3

Notes:

1. The use of a CEMS for NOx and CO (as required for PSD, discussed in Section 6.c above) constitutes a continuous compliance determination method (CCDM). According to 02D .0614(b)(1)(F), standards for which there are a CCDM are exempt from CAM. Therefore, CAM is not triggered per condition I.
2. Acid Rain Program requirements are exempt from CAM per 02D .0614(b)(1)(C). Therefore, CAM is not triggered per condition I.
3. CSAPR is an emissions trading program, which is exempt from CAM per 02D .0614(b)(1)(D). Therefore, CAM is not triggered per condition I.
4. DEC monitors NOx emissions from these turbines using the CEMS alternative for peaking units allowed by Appendix E 40 CFR Part 75. This method does not constitute a CCDM. Therefore, there is no exemption for the NSPS and PSD rules per condition I. Because these rules are not exempt from CAM, and because DEC uses water injection to comply with these rules (condition II), and because each turbine has pre-control potential emissions greater than the major source threshold (condition III), CAM applies to these turbines.
5. This is an emissions cap under Subchapter 02Q, which is exempt from CAM per 02D .0614(b)(1)(E). Therefore, CAM is not triggered per condition I.

Based on the above analysis, CAM only applies to the sixteen combustion turbines equipped with water injection systems.

In order to comply with CAM, the existing permit requires DEC to monitor the water-to-fuel ratio and load on each turbine and compare these to the values used to demonstrate compliance in the most recent emission testing.

In the existing permit, an excursion (as defined in 40 CFR Part 64) occurs when the monitored water-to-fuel ratio drops below the tested value, measured on a four-hour average. However, this is incorrect:

- The measuring period should be one hour to match the definition of "excess emission" under NSPS Subpart GG (§60.334(j)(1)(i)(A)).
- Periods where the water-to-fuel ratio drops below the test value should be considered an exceedance, not an excursion:
  - The definition of *exceedance* in 40 CFR Part 64 is "a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard…"
  - The definition of *excess emission* under NSPS Subpart GG is "any unit operating hour for which the average steam or water-to-fuel ratio…falls below the acceptable steam or water-to-fuel ratio needed to demonstrate compliance with [the NOx standard]" (§60.334(j)(1)(i)(A))
  - Any time the water-to-fuel ratio is less than the tested value is, by definition, an excess emission and therefore an exceedance under 40 CFR Part 64.

Based on the above definition of exceedance, the CAM requirements in the permit will be modified:

- The averaging time will be reduced to one hour to match NSPS Subpart GG,
- The term "excursion" will be replaced with "exceedance," and
- The QIP threshold, which is based on excursions, will be removed.

The permit will continue to require DEC to keep records of all exceedances, monitoring activities, and monitor downtime, and submit reports twice per year.

Compliance with the corrected CAM plan will be determined with subsequent inspections and reports.

e. <u>15A NCAC 02D .1111 "Maximum Achievable Control Technology" (MACT; 40 CFR Part 63)</u>

This rule incorporates the MACT standards under 40 CFR Part 63 into North Carolina's SIP. For the purposes of MACT applicability, this facility is a major source of hazardous air pollutants because it has the potential to emit more than 10 tons per year (tpy) of any individual hazardous air pollutant (HAP) and/or more than 25 tpy of total combined HAP. Rules that apply to Area Sources (e.g., the MACT standards for boilers under 40 CFR Part 63, Subpart JJJJJJ) do not apply to this facility.

There are two MACT rules that apply to this facility: Subparts YYYY and ZZZZ.

i. <u>MACT Subpart YYYY "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines"</u>

This rule applies to combustion turbines located at Major Sources. The rule specifies several subcategories of combustion turbines. The requirements of this rule differ based on the subcategory.

Existing stationary combustion turbines: §63.6090(b)(4) states that existing turbines do not have to meet the requirements of this rule. "Existing" means commenced construction or reconstruction on or before January 14, 2003. The sixteen turbines (ES-1 through 16) are existing, and therefore do not have to meet these requirements.

New turbines: ES-19 is considered a "new" and either "lean premix gas-fired" or "diffusion flame" stationary combustion turbine under this rule. §63.6095(d) states that such sources need only comply with the initial notification requirement of this rule. The other requirements of this rule are stayed until US EPA takes final action to require compliance and publishes a document in the Federal Register. §63.6175 states that, in order to be considered part of this category, the aggregate total time each turbine at this facility (regardless of applicability to this rule) fires fuel oil must be less than 1,000 hours per year. The existing permit requires DEC to keep a record of the total aggregate time of fuel oil burning at the facility in order to confirm ES-19 is part of this category.

Note that although they do not have to meet the requirements of this rule, each of these turbines are still subject to this rule because §63.6090(a) states that the rule applies to each affected source and that "an affected source is any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions."

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined based on subsequent inspections.

ii. MACT Subpart ZZZZ "National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines "

This rule applies to all stationary engines. The firewater pump I-18 is subject to this rule.

Under this rule, this engine is considered an existing, emergency-use engine located at an area source of HAP. In general, the requirements for such sources are:

- Change oil, belts, and filters on a regular schedule;
- Operate with good work practices according to manufacturer specifications;
- Keep records of maintenance activities and hours of operation; and
- Install a non-resettable hour meter.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections.

Note that this rule only applies to emission sources on the list of insignificant activities. Therefore, the Title V permit does not include a specific condition for this rule.

f. 15A NCAC 02D .1418: "New Electric Generating Units, Large Boilers, and Large I/C Engines"

This rule applies to electric generating units installed after October 31, 2000. The turbines ES-1 through 16 were installed before this date and ES-19 was installed after this date.

This rule specifically limits NOx emissions to the more stringent of 0.15 pounds per million Btu and any applicable limit under 02D .0530. Based on the emission limits in the permit, the PSD limit will be more stringent while ES-19 is in the validation phase of Versions A, B, and C, and at all times post-development. During periods of commissioning and testing phases of Versions A, B, and C, the limit under 02D .1418 is more stringent.

In order to demonstrate compliance with the NOx limit under this rule (when applicable), the facility will use the NOx CEMS data gathered to demonstrate compliance with PSD (discussed in Section 6.c). In addition, the facility must submit an annual report of the NOx CEMS performance during the ozone season (May 1 – September 30).

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

g. 15A NCAC 02Q .0317 "Avoidance Conditions"

This rule allows a facility to accept enforceable limits in order to avoid applicability of specific rules. DEC has accepted a limit on NOx to avoid PSD.

DEC has accepted an enforceable emission limit in order to avoid additional requirements under 02D .0530 (i.e., PSD Avoidance). The limit applies to the turbines ES-1 through 16 and requires that the total NOx emissions from these turbines be less than 384.2 tons during any ozone season (May 1 – September 30). This limit has been included in the Title V permit as of the R03 revision (issued February 12, 2002), which is the beginning of DAQ's electronic record of this permit.

In order to demonstrate compliance with this limit, DEC uses the NOx data gathered for the Acid Rain Permit during specifically the ozone season. DEC must submit an annual report of the NOx emissions during the ozone season.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

h. 15A NCAC 02Q .0400 "Acid Rain Procedures"

This rule incorporates the acid rain program (40 CFR Part 72) into North Carolina's SIP.

The specific requirements for the acid rain program are included in the Phase II permit application submitted by DEC. The Phase II permit application is included in the Title V permit as an attachment. In general, DEC is required to monitor and report NOx and SO_2 emissions.

In general, compliance with the acid rain program is determined by USEPA, not DAQ. Continued compliance will be determined by US EPA.

The existing permit includes a specific condition that requires DEC to submit a permit application to incorporate the new turbine ES-19 into the acid rain permit. This requirement was completed with the T13 permit revision, and therefore this requirement can be removed from the permit.

i. Cross State Air Pollution Rule ("CSAPR"; 40 CFR Part 97, Subparts AAAAA and CCCCC)

This group of rules applies to fossil-fuel-fired combustion sources that 1) produce electricity for sale, and 2) have a generator capacity greater than 25 megawatts. Each combustion turbine at this facility is subject to CSAPR.

CSAPR limits NOx and SO_2 emissions. In general, CSAPR requires tracking and trading emission credits across multiple facilities, including facilities not within the state of North Carolina. Therefore, compliance with CSAPR is generally determined by US EPA.

The existing permit includes a reference to 40 CFR Part 97, Subpart BBBBB "CSAPR NOX Ozone Season Group 1 Trading Program." This rule applies to areas that are part of the summer ozone season trading program. As of 2017, North Carolina is not such an area. Because Subpart BBBBB does not apply to this facility, all references to this rule have been removed from the permit. For further discussion of the nonapplicability of Subpart BBBBB, see Attachment 2.

Note that the CSAPR rules are not currently included in North Carolina's SIP. The Title V permit contains a reference to CSAPR and the relevant portions of 40 CFR Part 97, but no specific compliance requirements.

j. Nonapplicable Rules:

There are several SIP and Federal rules that could potentially apply at this renewal, but ultimately do not.

i. 40 CFR Part 60, Subpart IIII "Stationary Compression Ignition Internal Combustion Engines"

This rule applies to stationary engines based on their date of construction and their use within a facility (e.g., emergency use, fire pump, etc.). The engine I-18 is potentially subject to this rule.

This rule applies to fire pump engines that were manufactured after July 1, 2006. The engine I-18 was manufactured before that date, so this rule does not apply.

ii. 15A NCAC 02D .1100 "Control of Toxic Air Pollutants" and 15A NCAC 02Q .0711 "Emission Rates Requiring a Permit"

These rules may apply to facilities that make certain modifications that increase the emission rate of toxic air pollutants (TAP). Note that per 02Q .0702(a)(27), emission sources subject to a rule under 40 CFR Part 63 (i.e., subject to a MACT) are generally exempt from TAP emission requirements. Each source of TAP emissions at this facility is subject to a MACT, so the Title V permit does not contain any references to this rule.

As part of the T11 permit revision, DAQ examined TAP emissions from the facility using air dispersion modeling. As a result, DAQ determined that TAP emissions "will not present an unacceptable risk to human health based on dispersion modeling analysis."[5]

iii. 15A NCAC 02D .1423 "Large Internal Combustion Engines"

This rule applies to large internal combustion engines that are subject to 15A NCAC 02D .1418 but are also not subject to 15A NCAC 02D .0530.

This rule does not apply to turbines ES-1 through 16 because they are not subject to 02D .1418 (see Section 6.f). This rule does not apply to turbine ES-19 because it is subject to 02D .0530 (see Section 6.c). Therefore, this rule does not apply to any source at this facility.

iv. 15A NCAC 02D .2100 "Risk Management Program" (a.k.a. §112(r), Section 112(r) of the Clean Air Act)

This facility does not appear to store any materials above their respective thresholds in 40 CFR 68.130. Therefore, this facility is not required to submit a Risk Management Plan and has no

[5] See the application review for Title V permit 07171T11, issued June 20, 2018 (page 20).

specific requirements under 02D .2100. Note that other requirements under §112(r) (such as the General Duty Clause) may apply to this facility.

v. 15A NCAC 02Q .0504 "Option for Obtaining Construction and Operation Permit"

This rule covers how a facility can apply for a 2-part significant modification. DEC used the 2-step process with application .17A. In response to application .17A, DAQ issued the T11 permit revision. Because DEC used the option for a 2-part significant modification, Specific Condition 2.2 A.2 was included in the permit at that time.

In order to comply with the existing permit, DEC must submit a new permit application within 12 months of the beginning of operation of the turbine or associated fuel tank. In order to satisfy this requirement, DEC submitted application 5500082.21A. According to the application and subsequent correspondence with DEC, no substantial changes to the permit are necessary under this 2nd step application.

For ease of review, DAQ's review of the T11 revision of the Title V permit and associated application is included in this document as Attachment 1. The conclusions reached by DAQ's original review have not changed.

DEC has satisfied the requirements of this rule, and references to this rule will be removed from the permit.

7. Compliance Status and Other Regulatory Concerns:

- *Compliance status*: This facility was most recently inspected on August 5, 2020 by Emily Supple. DEC appeared to be in compliance with the Title V permit during that inspection.

- *Compliance history*: There have been no Notices of Violation issued to this facility since the previous Title V permit renewal.

- *Application fee*: Title V and Title IV permit renewals do not require an application fee. Applications for significant modification (i.e., application .21A) require an application fee. The appropriate fee was received on March 29, 2021.

- *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 Rule .0103 of this Section 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 PE Seal was **<u>NOT</u>** required for this Title V or Title IV permit renewal. The requirement for a PE Seal for the 2-step significant modification was addressed with application .17A (see Attachment 1).

- *Zoning*: A Zoning Consistency Determination per 15A NCAC 02Q .0304(b) was **<u>NOT</u>** required for this Title V or Title IV permit renewal. The requirement for a PE Seal for the 2-step significant modification was addressed with application .17A (see Attachment 1).

8. Facility Emissions Review

The table on the first page of this permit review presents the criteria pollutant (plus total HAP) from the latest available approved facility emissions inventory (2019). The HAP emitted in the largest quantity from the facility is formaldehyde.

The renewal of the Title V and Title IV permits, discussed in Sections 1.a and 1.b above, is not expected to change potential emissions from this facility.

The completion of the 2-step significant modification, discussed in Sections 1.c and 6.j.v above, is not expected to change potential emissions from this facility because all such changes were addressed in the first step of the significant modification process. See Attachment 1, Table 7-1 for a summary of emission changes associated with that modification.

9. Draft Permit Review Summary

Initial internal draft: An initial draft of the permit and application review were sent to RCO and SSCB staff (Mark Cuilla, Samir Parekh) on February 10, 2021. The comments received are summarized below.

SSCB comment 1: The CAM plan in the existing permit and initial draft needs the following revisions:

I. The excursion indicator range should be above the value that triggers a violation of NSPS Subpart GG. The email suggested a threshold of 105% of the tested water-to-fuel value.
II. The excursion indicator should be measured over a 1-hour period to be consistent with NSPS Subpart GG.
III. The QIP threshold should be lowered to 3% to match DAQ's good O&M threshold.
IV. The CAM plan should not automatically exclude periods of startup, shutdown, monitor malfunction, and operation under the Alternative Operating Scenario.

Response: The CAM plan was revised to address this comment. After proposing the revised CAM plan to DEC, additional changes and corrections were made. See Section 6.d for a discussion of CAM plan requirements and the CAM plan that was ultimately included in the permit.

SSCB comment 2: SSCB requested minor revisions to DEC's proposed language regarding CO CEMS requirements in Specific Condition 2.2 A.1.m of the draft permit.

Response: The language proposed by DEC had already been approved by DAQ in a letter from Stephen Hall, dated April 24, 2020.

RCO comment 1: Draft permit and review contain typos.

Response: The indicated issues have been corrected.

RCO comment 2: The permit and application review should be clearer with regards to the outstanding 2nd step application requirement (for instance, the footnote to the list of permitted emission sources).

Response: After this comment was received, DEC submitted the required 2nd step application. Therefore, these references will be removed from the permit.

RCO comment 3: Should the permit include a more complete and specific condition for NSPS Subpart KKKK and ES-19?

Response: No. The turbine ES-19 is under development, and development will not be complete for several years. During this time, much of NSPS Subpart KKKK will not apply. The permit requires DEC to submit a permit application once development of the turbine is finalized, and at that time the permit will include a full condition for NSPS Subpart KKKK.

RCO comment 4: The permit and application review appear inconsistent with the use of the terms "ozone season," "summer ozone season," "the restricted period," and the dates May 1 – September 30. Should these all be the same term? Is the time period correct?

Response: The correct term is "ozone season," which is May 1 to September 30, as defined in DAQ's rules. The permit will be updated to be more consistent using this term.

RCO comment 5: The CAM plan in the existing permit excludes periods of startup, shutdown, monitor malfunction, and operation under the Alternative Operating Scenario. Should this exclusion be removed from the permit?

Response: Yes, this exemption should be removed.

RCO comment 6: The existing permit allows 60 days to submit performance test results for PSD compliance testing. Should this be 30 days? (Specific Condition 2.2 A.1.s)

Response: Yes. General Condition JJ allows for 30 days to submit the test results and also allows for the facility to apply for an extension as needed.

Comments were resolved on April 5, 2021 and a new draft of the permit and application review were prepared.

Regional office draft: A draft of the permit and application review were sent to MRO on April 5, 2021. No comments were received.

Initial draft to applicant: A draft of the permit and application review were sent to DEC on April 5, 2021. DEC responded on May 3, 2021. The comments received are summarized below:

DEC comment 1: Would it be possible to include the Part II application that was submitted at the end of March rather than splitting the two permits?

Response: The Part II application (application .21A) is addressed with this permit revision, but the draft permit still contained a reference to the Part II application requirement. This reference will be removed.

DEC comment 2: Will startup, shutdown, and malfunction be excused from the CAM plan? The CAM plan should not automatically exclude periods of startup, shutdown, monitor malfunction, and operation under the Alternative Operating Scenario.

Response: Only if the underlying standard excuses such times. The Part 64 rules do not include an automatic blanket exemption for SSM.

DEC comment 3: [For the CAM plan] Will the allowed lookback period and the 6% per quarter for monitor downtime allowed by the DAQ CEMS enforcement document apply here? Is it possible to align in this manner? Will this be calculated across all 16 units?

Response: This comment refers to the QIP threshold of the CAM plan in the first draft permit. This has been removed from subsequent drafts, so this comment is no longer relevant. This being said, the CAM plan language (and QIP requirement) is separate from the good O&M CEMS policy It is not necessary to align CEMS 3% and 6% quarterly O&M requirement with the CAM QIP requirement, which is on a semi-annual basis.

DEC comment 4: Regarding CO CEMS and data substitution: "Per the approval letter for the harmonization, the unit is not subject to data substitution."

Response: This comment refers to a DAQ letter regarding CO CEMS and quality assurance (QA) procedures.[6] The purpose of this approval letter was to allow DEC to use QA procedures for the CO CEMS similar to those found in Part 75 for NOx and O_2 CEMS. The letter specifically notes that the CO CEMS are not subject to data substitution under Part 75. However, this is not a blanket exemption from data substitution for CO CEMS; data substitution for the purpose of demonstrating compliance with an emission limit is a separate issue from QA procedures. Therefore, DAQ can still require data substitution for CO CEMS when deemed necessary. See Section 6.c for a discussion of the data substitution requirements for CO CEMS at this facility.

Subsequent draft to applicant: Based on the above responses, DEC requested a meeting to discuss the changes to the CAM plan and CO CEMS data substitution requirements. This meeting was held via conference call on June 3, 2021. In this meeting, DEC questioned the need for CO CEMS data substitution and if CAM should even apply to this facility. These issues were discussed in additional calls on August 3 and August 13, 2021. As a result of these discussions, DEC agreed to CO CEMS data substitution during the June 3 call, and agreed to a modified CAM plan on October 1, 2021 via email. See Section 6.d for a discussion of CAM plan requirements.

10. Public Notice and EPA Review

A notice of the DRAFT Title V 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 15A 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 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 at or before the time notice is provided to the public under 02Q .0521 above. South Carolina is an affected state.

- The Public Notice and EPA Review periods began on XXXX.
- The Public Notice period ended on XXXX.

[6] Letter from Stephen Hall (Chief of DAQ's Technical Services Section) to Kristopher Eisenrieth (general manager, Duke Energy Corporation LCTS) and other DEC staff, dated April 24, 2020.

- The EPA Review period ended on XXXX.

11. Recommendations

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. 07171T14. MRO has received a copy of this permit and submitted comments that were incorporated as described in Section 9.

Attachment 1 to Application Review of Applications 5500082.20A, .20B, and .21A
Duke Energy Corporation LCTS
Application Review of Application 5500082.17A

Below is the preliminary determination published by DAQ on June 27, 2018. During the required 30-day public notice period, DAQ received no comments. DAQ issued the preliminary permit and associated application review without revision on August 1, 2018.

(Page numbers in this attachment may differ from the original document due to formatting differences)

Review Engineer: Rahul Thaker Review Engineer's Signature: Date: August 1, 2018 [Signed by Rahul Thaker on Permit Issue Date]	Comments / Recommendations: Issue 07171/T11 Permit Issue Date: 8/1/2018 Permit Expiration Date: 04/30/2021

1.0 Purpose of Application

Duke Energy Carolinas, LLC, Lincoln Combustion Turbine Station (hereinafter "DEC" or "LCTS"), submitted a Prevention of Significant Deterioration (PSD) application for the construction of a Siemens Energy test facility comprising of a new, advanced simple cycle combustion turbine ("CT"). This unit will be fired primarily with natural gas with No. 2 fuel oil as a back-up fuel. A new storage tank for No. 2 fuel oil will also be constructed, supporting the CT.

The application has been deemed "complete" for Prevention Significant Deterioration (PSD) with respect to the initial information submitted, as of 9/14/2017. As requested by the applicant, North Carolina Division of Air Quality ("DAQ") will process the application using the procedure in 15A NCAC 02Q .0501(c)(2) and .0504, satisfying the permitting requirements in 02D .0530 (PSD) only. The applicant will be required to submit another application within 12 months of commencement of operation of the above equipment, in accordance with 02Q .0500 "Title V Procedures".

2.0 Facility Information and Existing Operations

2.1 Site Description

The LCTS, located in Lincoln County, North Carolina (NC), is approximately 17 miles northwest of Charlotte, NC. The Station is located on a parcel of land north of Old Plank Road after the intersection of June Dellinger Road. The town of Lowesville is approximately 2 miles southeast of the Station. The coordinates of the Station are 496.605 km easting and 3920.854 km northing in Universal Transverse Mercator (UTM) Zone 17 (35.431° N latitude, 81.037° W longitude). Aerial and topographic maps of the site and the surrounding area are exhibited in Figures 2-1 and 2-2, respectively, as shown below. They indicate generally very rural land with agriculture and forested areas. The topography is generally rolling hills with terrain below stack top, except for some taller hills 10-15 kilometers to the northwest of the facility.

Figure 2-1: Location of Lincoln Combustion Turbine Station (Aerial View)

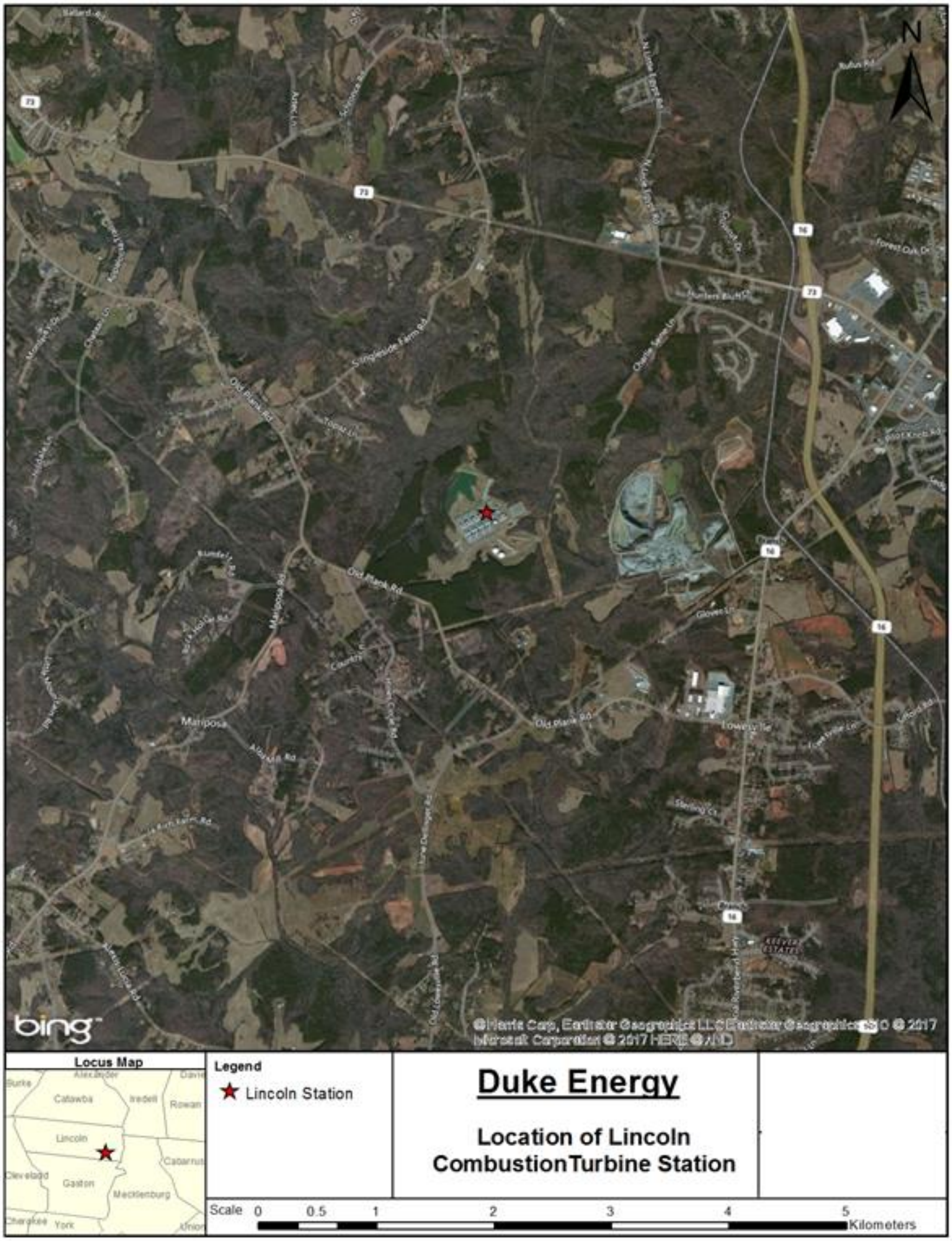
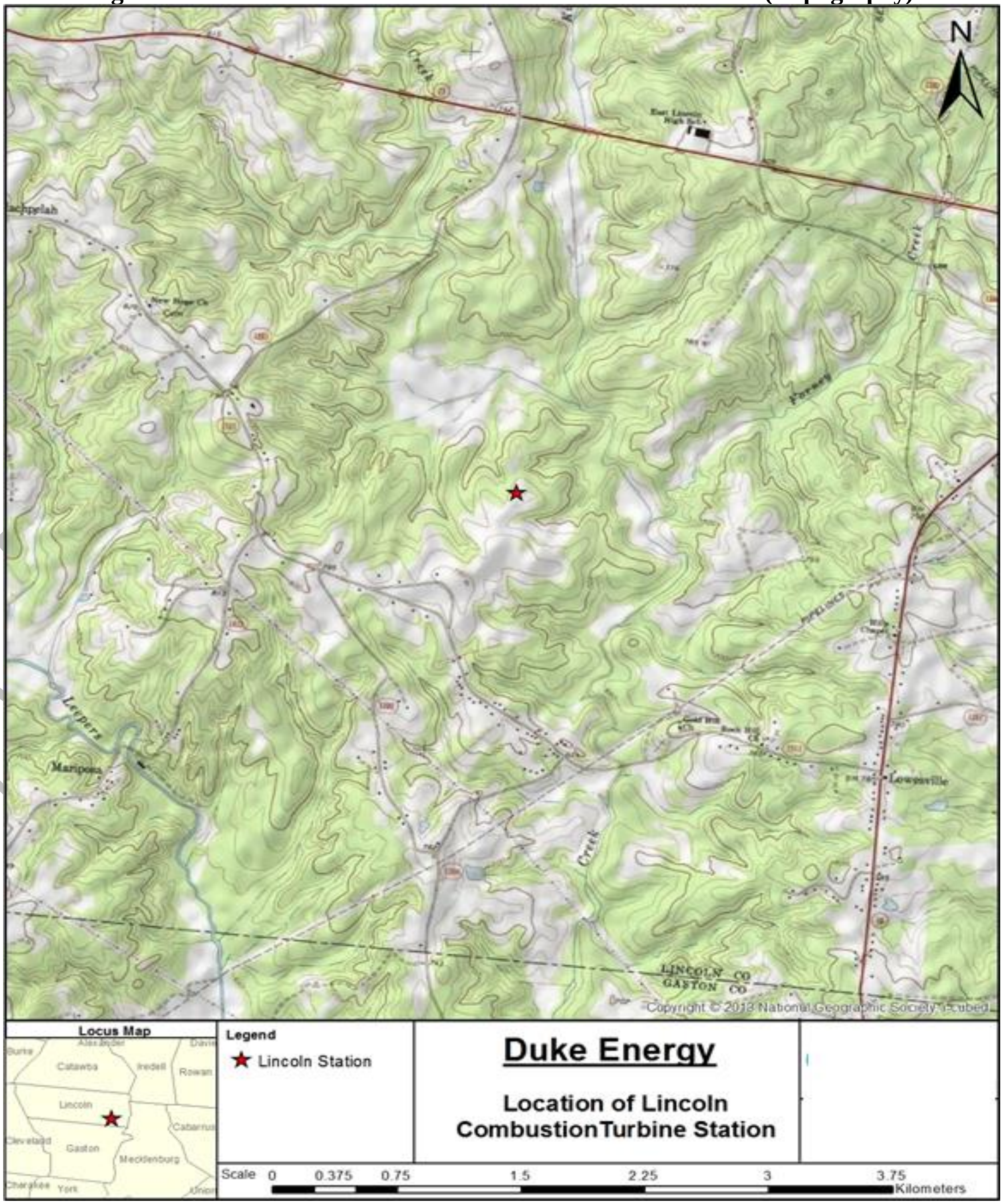


Figure 2-2: Location of Lincoln Combustion Turbine Station (Topography)



Current air quality designations for Lincoln County with respect to various National Ambient Air Quality Standards (NAAQSs) are described below in Table 2-1 in accordance with 40 CFR 81.334 "North Carolina":

Table 2-1: Attainment Status Designations

Pollutant	Designations
PM_{10}	Attainment (Both 1987 (annual) and 2012 (24-hour) NAAQSs)[1]
$PM_{2.5}$	Unclassifiable/Attainment (Both 2006 (24-hr) and 2012 (annual) NAAQSs)
Sulfur Dioxide	Attainment (1971 (annual) NAAQS), Attainment/Unclassifiable (2010 (1-hr) NAAQS)
Nitrogen Dioxide	Attainment (1971 (annual) NAAQS)[2], Unclassifiable/Attainment (2010 (1-hr) NAAQS)
Carbon Monoxide	Unclassifiable/Attainment (1971 (1-hr and 8-hr) NAAQS)[3]
Ozone	Attainment (2008 (8-hr) NAAQS)[4], Attainment/Unclassifiable (2015 (8-hr) NAAQS)
Lead	Unclassifiable/Attainment (2008 (3-month) NAAQS)

In summary, Lincoln County is either in attainment or unclassifiable/attainment of all promulgated NAAQS. Further, this County is considered a Class II area with ambient air increments for PM_{10}, $PM_{2.5}$, SO_2, and NO_2. The closest Class I area from this facility is Linville Gorge National Wilderness Area, which is located approximately 54 miles (87 kilometers) northwest of the facility.

2.2 Existing Operations

DEC owns and operates the LCTS, Stanly, Lincoln County, North Carolina. The Lincoln Station comprises of 16 natural gas/No. 2 fuel oil-fired simple cycle combustion turbines. Each unit is nominally rated at 1,313 million Btu per hour when firing natural gas and 1,247 million Btu per hour when combusting No. 2 fuel oil. These heat input rates are approximately equivalent to 90 MW of gross electrical output per unit (a total of 1,488 MW winter rating for 16 units). The facility also includes ancillary sources (i.e., fire water pump and fuel oil storage tanks) to support the operation of the combustion turbines. These existing combustion turbines are "peaking" sources which provide fast-start capacity to meet electric system demands during periods of high customer use.

The facility's primary business activity is classified under the Standard Industrial Classification code 4911 "Electric Services "[5]. Under North American Industrial Classification System (NAICS), it is classified under code 221112 "Fossil Fuel Electric Power Generation".

3.0 Proposed Modification

3.1 Project Sources

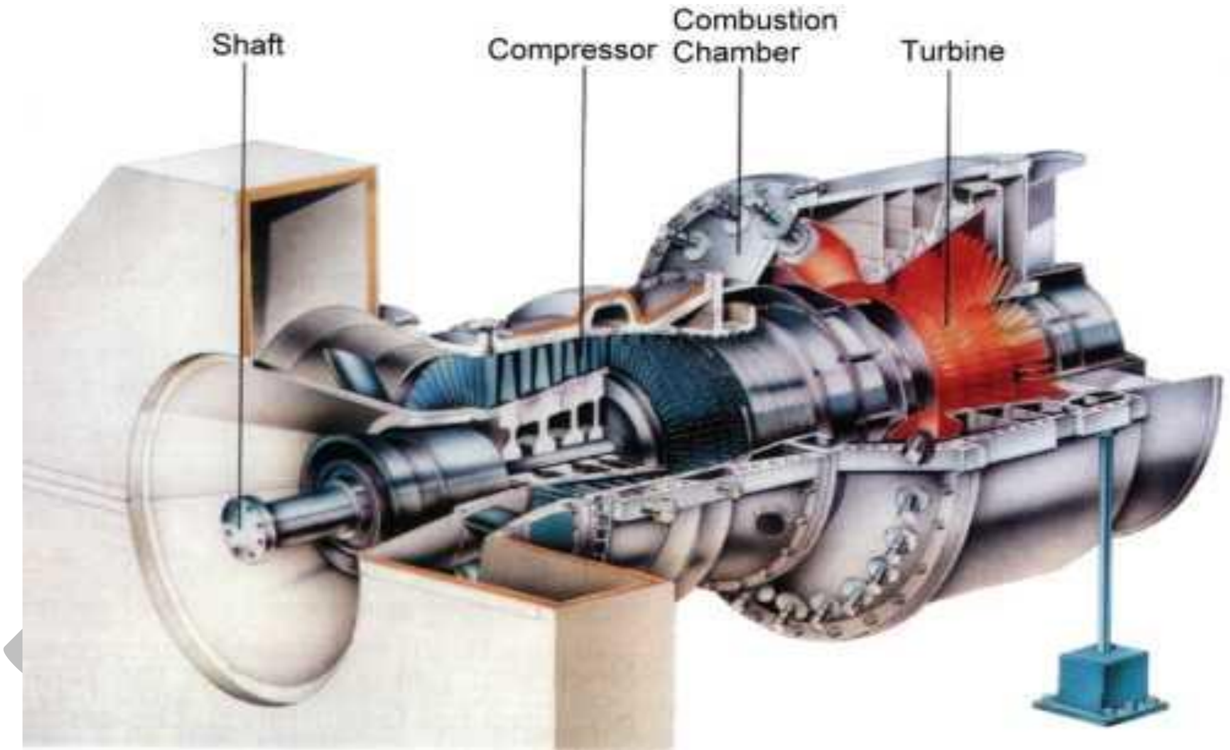
Combustion Turbines

The combustion turbines (also called "gas turbines") consist of three major components: compressor, combustor, and power turbine. First, the intake air is filtered, then, cooled using evaporative cooling techniques, and finally, compressed in a multiple-stage axial flow compressor. Then, the compressed air and fuel are mixed and burned in the turbine combustion chamber. Lean pre-mix dry low NOx combustors minimize the emissions of NOx while combusting natural gas. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and power generator. Exhaust gases exit the power turbine at approximately 1100^0F. The following Figure 3-1 shows major components of a typical simple cycle combustion turbine:

---

[1] Assumed. Lincoln County has been designated unclassifiable / attainment for more stringent PM2.5 NAAQSs for both 24-hr and annual averaging periods.
[2] The same 1971 NO_2 NAAQSs (primary and secondary) for annual averaging period were retained in 1985, 1996, 2010 and 2012.
[3] The same 1971 CO NAAQSs (primary) for both 1-hr and 8-hr averaging periods were retained in 1985, 1994 and 2011.
[4] The LCTS is located in the portion of Lincoln county (partial county), which was initially designated a nonattainment area. However, this partial non-attainment area has been re-designated as in attainment, effective August 27, 2015 (80 FR 44873, July 28, 2015).
[5] Includes establishments engaged in generation, transmission and/or distribution of electric energy for sale.

Figure 3-1: Simple Cycle Combustion Turbine



The combustion turbines are typically designed to operate in the dry low-NOx mode at loads from about 60 percent up to base load rating. The production of electricity using a combustion turbine engine coupled with a shaft driven generator is referred to as the Brayton Cycle. This power generation cycle has a thermal efficiency that generally approaches 40 percent. This is also referred to as "simple cycle" and has been traditionally utilized for electricity peaking generation since the unit and its output can be brought on line very quickly. The largest energy loss from the cycle is from the turbine exhaust in which heat is discarded to the atmosphere at about 1,100°F.

Proposed Simple Cycle Combustion Turbine

As stated in Section 1 above, DEC is proposing to construct a new, advanced simple cycle combustion turbine (J-class) with nominal ratings of 402 MW (winter rating) and 365 MW (summer rating), which will be sited adjacent to the existing simple cycle units. This new combustion turbine will be designed to compete with other advanced-class "H&J" series combustion turbines, introduced by other manufacturers, namely General Electric and Mitsubishi. This advanced-class turbine will provide higher (thermal) efficiency and faster ramp rates as compared to existing large frame turbines (i.e., 16 units).

The unit's design will be tested and validated through a sequence of three equipment configurations as below in Table 3-1:

Table 3-1: Equipment Configurations

	Version A	Version B	Version C
Nominal Net Capacity (winter/summer), MW	369 / 335	382 / 347	402 / 365
Maximum Gross Capacity, MW	Not Available	Not Available	571 (natural gas) 475 (fuel oil)
Maximum Heat Input Rate, million Btu/hr (HHV)	3,668 (natural gas) 3,028 (fuel oil)	3,764 (natural gas) 3,104 (fuel oil)	5,224 (natural gas) 4,375 (fuel oil)

Each of these versions will have their separate phases of commissioning, testing, and validating. Improvements will be made to the equipment between Versions A and B and Versions B and C to improve efficiency, and could include (but are not limited to) upgrades to the rotors, blades, and/or shell casing. The Version C configuration is expected to have the largest potential heat input and electrical output as indicated in Table 3-1 above. The combustion turbine will primarily burn natural gas with No. 2 fuel oil (i.e., ultra-low sulfur diesel (ULSD)) fuel as backup. Natural gas will be provided by the existing Piedmont Natural Gas pipeline, which currently serves the existing (16) units at the facility. Once Siemens Energy turns over the project to Duke Energy, it will provide peaking generating capacity to the Duke Energy Carolinas system.

The unit will essentially be a research and development (R&D) combustion turbine for the initial few years. As per the applicant, the unit will be the first of its kind. Extensive testing by Siemens will be required to ensure the technology is safe and reliable. The equipment will be tied to Duke Energy’s electrical grid and will be subject to dispatch availability for operation.

The combustion turbine will be equipped with testing sensors that will provide real-time data collection on the performance of key system components and ancillary systems during the commissioning, testing, and validation portions of each configuration. In general, two types of test requirements are expected for the new equipment:

- Short term testing to verify mechanical integrity, operational reliability, performance verification, technology screening and verification of operability at extreme ends of the operating envelope; and

- Long term testing to validate operational reliability for extended durations along with test data at real operating conditions, seasonal impact, validation of mechanical integrity for long term potential failure modes, long term performance verification, degradation mapping, and operability of design changes within a typical plant environment.

The new turbine will be designed to accommodate a dilution selective catalytic reduction (DSCR) system for control of NOx emissions and, if necessary to meet BACT limits, a catalytic oxidation system for control of CO and VOC emissions. The DSCR system and the oxidation catalyst are not expected to be installed during the initial commissioning and testing portions of each equipment version to avoid fouling the catalysts during initial startup of the equipment.

A new 2.5 million gallon No. 2 fuel oil storage tank will also be constructed to serve the proposed combustion turbine. It will satisfy its backup fuel needs, if there is a physical interruption in natural gas delivery to the facility or if natural gas becomes uneconomical due to (temporary) spike in the market price.

The applicant has confirmed that the proposed combustion turbine unit will be part of the existing major stationary source of LCTS, even though for Versions A, B, and partly for Version C, the subject turbine will be owned and operated by Siemens Energy. In summary, LCTS will assume all compliance obligations, air pollution control responsibilities, and all other air quality requirements for the combustion turbine under applicable North Carolina’s State Implementation Plan regulations, when and if a Prevention of Significant Deterioration (PSD) permit is granted by North Carolina Division of Air Quality (NC DAQ) for all configuration versions (A, B, and C).

3.2 Project Schedule

If a PSD permit is granted by the NCDAQ, construction on Version A would begin in 2018 and the first testing and validation phase will begin in late 2019. Version B is expected to have a commence construction date of early 2021, followed by testing and validation. Similarly, Version C is expected to have a commence construction date of the middle of 2022, followed by testing and validation. The duration of the testing and validation program planned for each Version will be approximately 12 months. Siemens will maintain care, custody, and control of the turbine equipment and tie it into the grid at the Lincoln Station throughout the testing program for Versions A, B and C. Following the completion of the testing portion of Version C, sometime in 2024, Duke Energy will assume care, custody, and control of the combustion turbine from Siemens and start utilizing it for commercial electric power generation.

It needs to be clearly stated that during the approximately four-year testing and validation period, Siemens will determine the timing and nature of operation of the unit; however, LCTS (Duke Energy) will receive the capacity at no cost and the energy will be delivered to the DEC grid at only the variable cost of the fuel. Moreover, Siemens will pay for any inefficient fuel use to the extent the unit is run out of (economic) dispatch order.

3.3 Project Emissions

Emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, lead, sulfuric acid mist, GHG, and some NC-regulated air toxics are expected due to the burning of natural gas and No. 2 fuel oil in the proposed unit. The changes in emissions on a worst-case basis for the Version C configuration (the largest of three Versions by heat input rate and power output rate), discussed in detail in Section 4.0, are summarized below, and reviewed for various regulatory applicability in Sections 4 through 10 below:

- Particulate Matter (PM filterable only): 31.3 tons/year (TPY) [increase]
- PM_{10}: 52.2 TPY [increase]
- $PM_{2.5}$: 52.2 TPY [increase]
- SO_2: 28 TPY [increase]
- NOx: 717.1 TPY [increase]
- CO: 822.9 TPY [increase]
- VOC: 119.6 TPY [increase]
- Lead: 0.02 TPY [increase]
- Sulfuric Acid Mist: 5.39 TPY [increase]
- GHG (as CO_2e): 1,401,411 TPY [increase]

The exit temperature for the gas turbine is $1{,}350^0$F with an exhaust flow rate of 5.55 million actual ft^3/min.

4.0 Regulatory Applicability

The proposed CT and No. 2 fuel oil storage tank will be subject to the following requirements:

<u>15A NCAC 02D .0521 "Control of Visible Emissions"</u>

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where visible emissions can be reasonably expected to occur, except during startup, shutdowns, and malfunctions, approved as such, according to the procedures approved under 15A NCAC 02D .0535.

For sources manufactured after July 1, 1971, visible emissions shall not be more than 20 percent opacity when averaged over a six-minute period. However, except for sources required to install, operate, and maintain continuous opacity monitoring systems (COMS), compliance with the 20 percent opacity limit shall be determined as follows:

i. No six-minute period exceeds 87 percent opacity;
ii. No more than one six-minute period exceeds 20 percent opacity in any hour; and
iii. No more than four six-minute periods exceed 20 percent opacity in any 24-hour period.

Excess emissions during startup and shutdown shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(g). Excess emissions during malfunctions shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(c).

All periods of excess emissions shall be included in the determinations in paragraphs i. and ii. above, until such time that the excess emissions are exempted according to the procedures in 2D .0535.

The proposed combustion turbine is subject to an opacity limit of 20%. No monitoring / recordkeeping/ reporting is required for visible emissions from natural gas/No. 2 fuel oil-fired CT, considering that these are clean fuels (negligible sulfur content in natural gas and 15 ppm sulfur content for ULSD) and visible emissions are expected to be non-existent to negligible.

15A NCAC 02D .0524 "New Source Performance Standards"

NSPS Subpart KKKK

The EPA promulgated a final regulation in Subpart KKKK "Standards of Performance for Stationary Combustion Turbines". They are promulgated in 71 FR 38482 on July 6, 2006 and codified in §§60.4300 through 60.4415 of 40 CFR.

Applicability

The regulation applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 million Btu per hour based on higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005. Only heat input rate to the combustion turbine should be included when determining whether this NSPS is applicable to the proposed turbines. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, the NSPS does apply to emissions from any associated HRSG and duct burners.

The construction of the proposed CT is expected to commence in 2018 if the permit is granted. The peak load heat input rate of the turbine is 5,224 million Btu/hr (HHV) when firing natural gas and 4,375 million Btu/hr (HHV) when firing fuel oil. Hence, the proposed combustion turbine is subject to this regulation.

However, per §60.4310(b), stationary combustion turbines engaged by manufacturers in research and development of equipment for combustion turbine control techniques or combustion turbine efficiency improvements are exempt from the NOx emission limits in §60.4320 on a case-by-case basis. The DAQ determined on June 8, 2017[6] that the above-mentioned CT would be "research and development" equipment; thus, it would be exempt from the applicable NOx limits until it would begin commercial operation. The letter further states that upon start of commercial operation, all applicable requirements in NSPS Subparts KKKK and A would apply. Thus, the permit stipulation will include all applicable NOx requirements including NOx limits, with a clear demarcation of upon placing the CT into commercial operation.

Emission Limits for NO_x

As stated above, upon commencement of commercial operation, the proposed CT will be subject to an emission standard of 15 ppm at 15 percent O_2 or 0.43 lb/MWh, when fired with natural gas. This turbine will also be subject to an emission standard of 42 ppm at 15 percent O_2 or 1.3 lb/MWh, when fired with No. 2 fuel oil. If the turbine operates in partial load (less than 75 percent of peak load) or if the turbine operates at temperatures less than 0 ^{0}F, the NOx limit of 96 ppm at 15 percent O_2 or 4.7 lb/MWh would apply.

As discussed in Section 5.0 below, the proposed CT is required to reduce NOx emissions to 9 ppm at 15 percent O_2 using low-NOx combustors and dilution selective catalytic reduction while burning natural gas, and 12 ppm at 15 percent O_2 using water injection and dilution selective catalytic reduction while burning fuel oil, both under the

[6] William Willets, Chief, Permitting Section, NCDAQ to Michael Brissie, Station Manager, Duke Energy Corporation LCTS.

validation phase (i.e., before the start of commercial operation). Hence, compliance with the above NOx emission limits is expected. The actual compliance with these emission standards will be verified during the initial performance test.

Emission Limits for SO_2

These turbines 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/million Btu heat input. The Permittee has chosen to comply with input-based emission standard for SO_2.

The turbine will burn pipeline quality natural gas or ultra-low sulfur diesel. Using 0.2 grains sulfur/100 ft^3 sulfur content and 1,020 Btu/standard ft^3 (HHV) heat content for natural gas, the SO_2 emission rate can be estimated as 0.00056 lb/million Btu. Similarly, using sulfur content of 0.0015%w in diesel fuel and heat content of 19,600 Btu/lb (HHV), the SO_2 emission rate can be estimated as 0.00153 lb/million Btu. Hence, compliance is expected while firing natural gas and fuel oil.

General Compliance Requirements

The Permittee shall operate and maintain the CT, dry low NOx burners, DSCR, and any monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions, at all times, including duration of start-ups, shutdowns, and malfunction.

Monitoring

If the Permittee is not using water injection to control NOx emissions and none of the alternatives described below, the Permittee must perform annual performance tests (subsequent to initial performance test) to demonstrate continuous compliance. If the NOx results are less than or equal to 75 percent of the NOx emission limit for the turbine, the frequency of testing can be reduced to once every two years for subsequent performance tests. If the results of any subsequent performance test exceed 75 percent of the NOx emission limit, the Permittee must resume the annual performance tests.

As an alternate to the annual performance tests, the Permittee can

- install, calibrate, maintain, and operate NOx CEM or
- install, calibrate, maintain, and operate applicable continuous parameter monitoring systems for dry low-NOx combustors and SCR or
- with the DAQ approval for the affected units which are also subject to Part 75, monitor the NOx emission rate using the Part 75 Appendix E methodology or the low mass emissions methodology in §75.19.

The Permittee must monitor the total sulfur content of the fuel being fired in the turbine, except that the Permittee can elect not to monitor the total sulfur content of the fuel combusted in the turbine provided that the fuel is demonstrated not to exceed potential sulfur emissions of 0.06 lb SO_2/million Btu heat input.

To make a demonstration that the potential sulfur emissions of 0.06 lb SO_2/million Btu heat input are not exceeded, the Permittee can elect to use valid purchase contract, tariff sheets or transportation contract showing the total sulfur content for natural gas is less than 20 grains of sulfur or less per 100 standard ft^3 and that the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw) or less. Alternatively, the Permittee can use representative fuel sampling data to show that the sulfur content of the natural gas does not exceed 0.06 lb SO_2/million Btu heat input.

If the Permittee chooses to not demonstrate compliance with the sulfur content of the fuel as above and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day. The Permittee can also develop custom fuel schedules to determine total sulfur content of gaseous fuels. The regulation includes two, custom sulfur monitoring schedules, which are available without prior EPA approval.

Reporting

For the affected unit, required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this Subpart, the Permittee must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. For the affected unit that performs annual performance tests in accordance with §60.4340(a), the Permittee must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Performance Tests

The Permittee is required to conduct initial and subsequent performance tests as per §60.4400 and §60.4415 for NOx and sulfur dioxide, respectively, with such exemptions as may be allowed.

NOx

The following performance testing requirements for NOx apply only after the unit ceases to become a research and development equipment (i.e., commercial operation after the unit is turned over to Duke Energy from Siemens Energy).

The Permittee is required to conduct an initial performance test within 60 days after achieving the maximum production rate but not later than 180 days of initial start-up for NOx for each combustion turbine.

The Permittee is required to perform annual testing (no more than 14 calendar months following the previous performance test) for NOx, if the Permittee is not using water injection to comply. The Permittee will be using NOx CEMS as per §§60.4335(b) and 60.4345. Therefore, consistent with §60.4340(b), this monitoring will satisfy the annual stack testing requirement.

SO_2

The Permittee is required to conduct an initial performance test within 60 days after achieving the maximum production rate but not later than 180 days of initial start-up for sulfur dioxide on each turbine.

Each subsequent test for sulfur dioxide shall be conducted once every year (no more than 14 calendar months following the previous performance test). As per §60.4415, the Permittee can opt for a fuel sulfur limit to comply with the sulfur stack-testing requirement.

If the Permittee opts to determine fuel sulfur to comply with this requirement, then the Permittee must **monitor** total sulfur content of the fuel being fired in the turbine. The sulfur content of the fuel must be determined using total sulfur methods in §60.4415. The Permittee must monitor natural gas once per unit operating day if the fuel is supplied without intermediate bulk storage.

Alternatively, the Permittee can choose **not to monitor** the total potential sulfur emissions of the fuel combusted in the turbine, if it can be demonstrated that the fuel does not exceed 0.06 lb SO_2/million Btu in continental areas. This demonstration can be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum sulfur for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet and that the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw) or less. The other option for demonstration is through representative fuel sampling data showing that the potential sulfur emissions of the fuel do not exceed 0.06 lb SO_2/million Btu in continental areas. In this case, the Permittee must provide at a minimum the amount of data in Section 2.3.1.4 or 2.3.2.4. of Appendix D of Part 75.

NSPS Subpart TTTT

Applicability

The EPA promulgated a final regulation in Subpart TTTT "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units" through 80 FR 64648, October 13, 2015. They are codified in §§60.5508 through 60.5580 of 40 CFR. The Subpart regulates pollutant CO_2 from electric generating units.

GHG standards included in this subpart apply to any steam generating unit, integrated gasification combined cycle (IGCC) unit, or stationary combustion turbine, that commenced construction after January 8, 2014 or commenced modification or reconstruction after June 18, 2014; 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 serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system. [§60.5509(a)]

Emission Standards

The NSPS includes emissions standards for three subcategories of new stationary combustion turbines in Table 2 to Subpart TTTT, as follows. These subcategories reflect actual fuel utilization and type of fuel fired:

Table 4-1: CO_2 Emissions Standards for New Stationary Combustion Turbines

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).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in §60.5525.

As per the Permittee, the proposed CT would be deemed either a non-base load, natural gas-fired unit (if the unit combusts more than 90 percent on a heat input basis based on 12-operating month rolling average basis, see second row in above Table) or a multi-fuel fired unit (if the unit combusts 90 percent or less natural gas on a heat input basis on a 12-operatitng month rolling average basis, see third row in the above Table). The Permittee contends that the unit is not expected to be designed for complying with the output based standard or as a base load unit (see first row in the above Table).

For the new unit to be classified as non-base load unit, it must supply no more than its design efficiency or 50 percent, whichever is less, times its potential electric output, as net-electric sales, either a 12-operating month or a 3-year rolling average basis. The Permittee has calculated the new turbine's potential annual emissions for purposes of PSD applicability and annual criteria pollutant modeling analyses, based upon the expectation that the unit will be designed to operate as non-base load (i.e., expected design efficiency and potential electric output for Version C). The Permittee has estimated an output threshold of 1.855 million MW-h to classify the proposed CT as a non-base load natural gas fired unit.

For natural gas firing (combusting more than 90 percent natural gas on a heat input basis), the maximum emission rate and heat input rate are 602,667 lbs/hr and 5,224 million Btu/hr, respectively. They correspond to a normalized emission rate of approximately 115 lbs/million Btu. Similarly, based on the maximum emission rate of 694,934 lbs/hr and a heat input rate of 4,375 million Btu/hr, both for fuel oil firing, the normalized emission rate would be approximately 159 lbs/million Btu. Thus, it is concluded that the proposed turbine would comply with the above emissions standards for a non-base load natural gas fired unit and a multi-fuel fired unit.

Monitoring / Record keeping / Reporting / Notifications

Stationary combustion turbines subject to heat input standards in Table 2 to the Subpart that are permitted to burn one or more uniform fuels (consistent chemical characteristics) that result in CO_2 emissions equal to or less than 160 lb/million Btu are not subject to any monitoring or reporting requirements, and they need to only keep purchase records of the permitted fuels. The uniform fuels as defined are natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. [§60.5520(d) and (d)(1), and §§60.5525 and 60.5535(a)]

The proposed turbine is to be permitted to burn both natural gas and No. 2 fuel oil; thus, it does meet the above uniform fuel criteria. In addition, as shown above, it is expected to comply with both emissions thresholds of 120 lb/million Btu and 120 to 160 lb/million Btu. Thus, the CO_2 emissions are expected to be equal or less than 160 lb/million Btu. Therefore, no monitoring or reporting requirements apply under this NSPS and the Permittee needs to only maintain the purchase records for natural gas and No. 2 fuel oil.

The Permittee is required to submit an initial notification of the date for commencement of construction of an affected facility, no later than 30 days after such date, pursuant to §§60.7(a)(1). In addition, the Permittee is required to submit an initial notification for the actual date of initial start-up of the affected facility, postmarked within 15 days after such date, pursuant to §§60.7(a)(3). [§60.5560(a)]

The proposed turbine is subject to the Acid Rain Program; hence, the Permittee is required to follow all applicable recordkeeping requirements and keep records as required under Subpart F of Part 75 (of 40 CFR), and submit all applicable notifications specified in §75.61. [§§60.5550(b) and 60.5560(b)(1)]

The records required pursuant to Subpart TTTT shall be in a form suitable and readily available for expeditious review. In addition, the Permittee shall maintain each record for 3 years after the date of conclusion of each compliance period. The Permittee shall maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. The Permittee may maintain the records off site for the remaining year(s) as required by this Subpart. [§60.5565(c)]

15A NCAC 02D .0530 "Prevention of Significant Deterioration"
15A NCAC 02D .0544 "Prevention of Significant Deterioration for Greenhouse Gases"

United States (US) Congress first established the New Source Review (NSR) program as a part of the 1977 Clean Air Act Amendments and modified the program in the 1990 amendments. The NSR program includes requirements for obtaining a pre-construction permit and satisfying all other preconstruction review requirements for major stationary sources and major modifications, before beginning actual construction for both attainment areas and non-attainment areas. The NSR program for attainment and non-attainment areas are called "Prevention of Significant Deterioration" (PSD) and "Non-attainment New Source Review" (NAA NSR), respectively. The NSR focuses on industrial facilities, both new and modified, that create large increases in the emissions of specific pollutants.

The basic goal for PSD is to ensure that the air quality in attainment areas (e.g., Lincoln County NC for PM_{10}, $PM_{2.5}$, NO_2, SO_2, CO, ozone, and lead) does not significantly deteriorate while maintaining a margin for future industrial growth.

Under PSD, all major new or modified stationary sources of air pollutants as defined in §169 of the CAA must be reviewed and permitted, prior to construction, by EPA and/or the appropriate permitting authority, as applicable, in accordance with §165 of CAA. A "major stationary source" is defined as any one of 28 named source categories (e.g., "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input"), which emits or has a potential to emit (PTE) of 100 tons per year of any "regulated NSR pollutant", or any other stationary source (i.e., other than 28 named source categories), which emits or has the potential to emit 250 tons per year of any "regulated NSR pollutant".

Pursuant to the Federal Register (FR) notice on February 23, 1982 (47 FR 7836), North Carolina (NC) has a full authority from the US Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. NC's State Implementation Plan (SIP) - approved PSD regulation has been codified in 15A NCAC 02D .0530, which implement the requirements of 40 CFR 51.166 "Prevention of Significant Deterioration of Air Quality" with a few exceptions as included in the approved regulation. The version of the CFR incorporated in the NC's SIP regulation is that of July 1, 2014 and it does not include any subsequent amendments or editions to the referenced material. Refer to Table 1 to §52.1770.

The LCTS is not one of the listed 28 source categories source. Therefore, the 250 tons/yr major stationary source classification applies. The facility is an existing PSD major stationary source; because, it emits or has a potential to emit 250 tons per year or more of several regulated NSR pollutants: PM_{10}, $PM_{2.5}$, SO_2, NO_x (as NO_2), CO, and VOC.

Because the existing facility is considered a major stationary source, any modification to an existing major source resulting in both significant emission increase and net significant emissions increase for a regulated NSR pollutant, is subject to PSD review and must meet appropriate review requirements.

The Permittee has performed a PSD applicability analysis as follows, for the modification (project) for determination of whether the project results in an emission increase of any regulated NSR pollutant above the applicable significance thresholds. Using the "Actual-to-potential test for projects that only involve construction of a new emissions unit(s)" in §51.166(a)(7)(iv)(d) (as implemented through 02D .0530), the Permittee has performed calculations for potential to emit [PTE] (post-change) for each regulated NSR pollutant expected to be emitted from each new unit. The baseline actual emissions [BAE] (pre-change), resulting from initial construction for each new unit, are zero by definition in §51.166(b)(47).

As described above this new advanced simple cycle combustion turbine's developmental program will consist of a sequence of three equipment configurations. The Version C configuration is expected to have the largest potential heat input and electrical output as mentioned above. Therefore, this C version is the basis of the annual potential emission rate (PTE) estimates, considering the non-base load unit status as stated above pursuant to NSPS Subpart TTTT.

As per the applicant, the combustion turbine's emissions profile will vary across the commissioning, testing, and validation phases of each equipment configuration. Further any external air pollution controls that may be required to meet the Best Available Control Technology (BACT) requirements are not expected to be installed during the commissioning phases of each configuration to prevent fouling of the catalyst materials. Also, the external air pollution control systems' effectiveness may be minimized during the testing phase of each configuration due to operational variability (e.g., multiple startups, shutdowns, and load changes). In addition, emissions during start-up and shut-down will be significantly different than emissions during normal operating times. Consequently, short-term NO_x, CO, and VOC emission rates are expected to be higher during the commissioning phase and startup/shutdown events than during operation at normal and maximum loads during the testing and validation phases of each configuration.

Estimated emission rates of NO_x, CO, VOC, SO_2, PM, PM_{10}, and $PM_{2.5}$ from the combustion turbine are developed using performance and emissions concentration data supplied by Siemens for both natural gas and fuel oil firing scenarios. EPA emission factors from 40 CFR 98 are used to estimate individual GHG compound emission rates (CO_2, CH_4, and N_2O). Total GHG emission rates, expressed in carbon dioxide equivalents (CO_2e) are developed by summing the individual GHG compound emission rates multiplied by each compound's global warming potential (GWP). Lead and hazardous air pollutant (HAP) emission rates are estimated using US EPA AP-42 emission factors.

Electric Power Research Institute (EPRI) method is used to estimate potential emission rates of sulfuric acid from the new turbine for both the natural gas and fuel oil firing scenarios. The EPRI emissions estimating methodology includes two separate contributions: direct formation of sulfuric acid from fuel combustion, and indirect formation through oxidation of SO_2 to SO_3 associated with the external air pollution control systems. The methodology also includes consideration of the impact of SO_3 reacting with ammonia slip from the DSCR system. To be conservative, this potential decrease in the sulfuric acid emission rate from the combustion turbine system is ignored by the applicant.

Potential emissions for PSD applicability are estimated by accounting for the projected emissions contribution from all three phases of operation (commissioning, testing, and validation), and startups and shutdowns, based on the worst-case (Version C) operating configuration. This assessment assumes that the commissioning, testing, and validation configurations occur sequentially in a 12-month period. Emissions during commissioning phase are estimated based on the projected operating hours for different fuel burning scenarios (300 hours each for natural gas and fuel oil). Emissions during the testing phase are estimated based on the projected number of testing hours on various fuels (600 hours on natural gas and 100 hours on oil). During the testing phase, the DSCR system is not expected to be in operation during oil firing, but it will be operational for 100 hours during gas firing. Emissions of each pollutant during startups and shutdowns are estimated based on the projected number of such events during each operating phase (a total of 327 events each for startup and shutdown when firing natural gas, and 45 events each for startup and shutdown when firing oil) and the projected duration of each startup/shutdown event. For the balance of the year (assuming non-base load operation under NSPS Subpart TTTT), the system is assumed to be in continuous operation at full load using the worst-case (by pollutant) fuel. Full load emission rates are conservatively estimated assuming operation at the lowest anticipated ambient temperature at the site.

This methodology results in the worst-case annual emission rates because the system is not expected to operate continuously during any of the Versions. The estimated potential to emit (PTE) emissions are also conservative because fuel consumption (and thus emission rates) will be higher for the Version C configuration than for Version A or Version B. Finally, a small amount of VOC emissions expected (1.4 tons/yr, based on EPA's TANKS program) from the new No. 2 fuel oil tank, have also been accounted in the project total emissions. Thus, the following Table 4-2 provides a summary of change in emissions due to the project:

Table 4-2: Emissions Changes Due to Proposed Project

Regulated NSR Pollutant	Baseline Actual Emissions Tons Per Year	Potential to Emit Emissions Tons Per Year	Emissions Change (Increase/Decrease) Tons Per Year	Significant Emission Rate Tons Per Year	Major Modification Review Required?
PM[7]	0	31.3	31.3	25	Yes
PM_{10}	0	52.2	52.2	15	Yes
$PM_{2.5}$	0	52.2	52.2	10	Yes
SO_2	0	28	28	40	No
NOx (as NO_2)	0	717.1	717.1	40	Yes
CO	0	822.9	822.9	100	Yes
VOC	0	121	121	40	Yes
Lead	0	0.02	0.02	0.6	No
Sulfuric Acid Mist	0	5.59	5.59	7	No
GHG as CO_{2e}	0	1,401,411	1,401,411	75000	Yes

It should be noted that the combustion emissions due to burning of natural gas and No. 2 fuel oil are all stack emissions; hence, fugitive emissions are not expected. VOCs emissions from the storage tank are fugitive in nature. Finally, the PTE for both PM-10 and PM2.5 include filterable and condensable portions, but for PM, it includes only the filterable portion, pursuant to §51.166(b)(49)(i)(a).
As shown in the Table 4-2 above,

- The change in emissions for SO_2, lead, and sulfuric acid mist do not exceed the applicable significance thresholds. Therefore, the proposed project is not a major modification for these pollutants.

[7] Filterable only.

- For PM, PM_{10}, $PM_{2.5,}$ NOx, CO, VOC, and GHG, the change in emissions exceed their respective significance thresholds. Thus, major modification review is required for these pollutants, with the presumption that the project also causes significant net emissions increase. Note that the applicant did not provide any net emission increase analysis for these pollutants.

  It needs to be emphasized that the major modification for GHG is triggered for the project; because, the project is a major modification to the existing major stationary source of LCTS for at least one non-GHG pollutants, such as PM, PM_{10}, $PM_{2.5,}$ NOx, CO, VOC. This is consistent with the requirements in 02D .0544(a) and UARG v. EPA[8].

Thus, LCTS is required and has performed the following reviews and analyses for emissions of PM, PM_{10}, $PM_{2.5,}$ NOx, CO, VOC, and GHG, to be emitted from the new CT and the No. 2 fuel oil storage tank. These reviews and analyses are required for each affected new or modified emission unit causing or contributing to an emission increase of any regulated NSR pollutant equaling or exceeding its significance threshold, as per 15A NCAC 02D .0530 and .0544.

- BACT analysis
- Air quality analysis
- Source impact analysis
- Additional impact analysis
- Class I analysis

However, it needs to be emphasized that "there are currently no NAAQS or PSD increments established for GHGs, and therefore these PSD requirements [i.e., NAAQS and PSD increment compliance, air quality analysis, additional impact analysis, and Class I analysis) would not apply for GHGs, even when PSD is triggered for GHGs."[9] Further the federal agency (EPA) has opined that "compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG".[10] In summary, only the BACT analysis portion of the PSD requirement applies for GHG for any major stationary source or a major modification to an existing major stationary source.

Refer to Sections 5.0 through 9.0 below for discussions on these requirements.

15A NCAC 02D .1111 "Maximum Achievable Control Technology"

EPA has promulgated a §112(d) MACT in 40 CFR 63 Subpart YYYY "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines", 69 FR 10512, March 5, 2004.

This Subpart applies if the facility is a major stationary source for emissions of hazardous air pollutants (HAPs). That is, the emissions are at least 10 tons/yr (single HAP) or 25 tons/yr (aggregate HAPs).

§63.6090(a)(2) defines the "new stationary combustion turbine" as any stationary combustion turbine with commence construction date after January 14, 2003.

The Subpart includes standards and associated requirements (testing, initial compliance, continuous compliance, reporting, and record keeping) for different subcategories (lean pre-mix gas fired, lean pre-mix oil fired, diffusion fame gas fired, diffusion flame oil fired, etc.).
Per final rule in 69 FR 51184 (August 18, 2004), EPA has stayed the effectiveness of requirements for two subcategories of "new" sources: lean pre-mix gas fired turbines and diffusion flame gas fired turbines. Only initial notifications requirement shall apply pursuant to §63.6145 and no other requirements under this NESHAP shall apply.

---

[8] Slip Opinion, *Utility Air Regulatory Group v. Environmental Protection Agency*, Supreme Court of the United States, June 23, 2014.
[9] Page 31520 at 75 FR 31514, June 3, 2010.
[10] Page 48, PSD and Title V Permitting Guidance for Greenhouse Gases, Prepared by the OAQPS, US EPA, RTP, NC 27711, March 2011.

The proposed turbine is a "new" affected source located at a major stationary source (facility). It is required to comply with only the applicable initial notifications requirement for gas fired category. Finally, standards for new oil-fired units apply to the proposed unit if all combustion turbines at the facility including the proposed turbine collectively burn fuel oil for more than 1000 hour per calendar year. The permit stipulation will include applicability of standards for oil-fired units for the condition described above.

15A NCAC 02D .1418 "New Electric Generating Units, Large Boilers, and Large I/C Engines"

This regulation applies to combustion turbines, permitted after October 31, 2000, serving a generator with a nameplate capacity greater than 25 megawatts electric and selling any amount of electricity.

The proposed combustion turbine will be permitted (if the permit is granted) after 2009 and its generating capacity will be 571 MW electric on natural gas and 475 MW electric on fuel oil. Hence, it is subject to the regulation.

NOx emissions from the source cannot exceed 0.15 lb/million Btu for gaseous fuel and 0.18 lb/million Btu for liquid fuel, or the NOx emissions from the turbines cannot exceed BACT limits established under 2D .0530 provision, whichever requires the greater degree of reduction.

NOx emission limits established pursuant to 02D .0530 will be more stringent than 0.15 or 0.18 lb/million Btu limits. Specifically, for validation phase and commercial operation, NOx emission rate for natural gas firing, corresponding to the proposed BACT of 9 ppm, is 0.033 lb/million Btu. Similarly, NOx emission rate for fuel oil firing, corresponding to 12 ppm of proposed BACT, is 0.047 lb/million Btu. Hence, compliance with these BACT limits will ensure compliance with the standards in 02D .1418, during validation phase of each configuration (Versions A, B, and C) and commercial operation.

However, during commissioning and testing phases of each configuration (Versions A, B, and C), the BACT limit of 45 ppm corresponds to 0.164 lb/million Btu. Thus, the Permittee shall comply with the emissions limits in this Section 02D .1418 (0.15 lb/million Btu or 0.18 lb/million Btu, as applicable), when firing natural gas or fuel oil, instead of the BACT, during commissioning and testing phases of each configuration (Versions A, B, and C).

All applicable provisions for monitoring including recordkeeping, and reporting shall apply under this Section.

15A NCAC 02Q .0400 "Acid Rain Procedures"

The proposed simple cycle combustion turbine is an affected fossil-fuel fired "new" unit (i.e., commence 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.

The Permittee will be required to apply to the DAQ for an Acid Rain permit at least 24 months before it commences operation and obtain such a permit from the agency. The Permittee will be required to monitor and report emissions under Part 75 (40 CFR) for both NOx and SO_2, and hold allowances for SO_2 under Parts 72 and 73 (40 CFR).

15A NCAC 02D .0614 "Compliance Assurance Monitoring"

The Compliance Assurance Monitoring (CAM) regulation generally applies to any pollutant-specific emissions unit (PSEU) that meets the following criteria:

- The emission unit must be located at a major source for which a Part 70 or Part 71 permit is required.
- The emission unit must be subject to an emission limitation or standard.
- The emission unit must use an (active) control device to achieve compliance with the emission limitation or standard.
- The emission unit must have potential, pre-controlled emissions of the pollutant of at least 100 percent of the major source threshold.

However, there are some exemptions in this regulation. For example, the rule does not apply to emission limitations or standards proposed after November 15, 1990, pursuant to section 111 or 112 of the Clean Air Act (e.g., post-1990 NSPS or NESHAP) or where a continuous compliance determination method (e.g., CEMS) is used.

This application is processed using the state construction and operation permit program in 02Q .0300 and not under the Title V program in 02Q .0500; hence CAM applicability does not need to be addressed for the proposed combustion turbine at this time.

15A NCAC 02Q .0700 "Toxic Air Pollutant Procedures"
15A NCAC 02D .1100 "Control of Toxic Air Pollutants"

The facility has not been previously triggered under the NC's air toxics permitting program. With this application, there are increases in emissions of certain toxics air pollutants, causing exceedance of toxic air pollutant emission rates (TPERs) in 15A 02Q .0711. Per 02Q .0700, toxic air pollutant (TAP) compliance demonstration is required for new or modified sources to ensure TAPs from the facility will not cause any acceptable ambient level (AAL) listed in 15A NCAC 02D.1104 to be exceeded beyond the property line. A facility-wide air toxics evaluation is performed to determine the pollutant(s) exceeding the toxic pollutant emission rate (TPER), as included in Table 4-3 below:

Table 4-3: Air Toxics Evaluation

Pollutant	Facility Total			NC TPER				Exceed any TPER?
				Carcinogens	Chronic Toxicants	Acute Systemic Toxicants	Acute Irritants	
	lb/yr	lb/day	lb/hr	lb/yr	lb/day	lb/hr	lb/hr	
Metal Compounds:								
Arsenic	8.61E+02	6.42E+00	2.68E-01	0.053				Yes
Beryllium	2.43E+01	1.81E-01	7.55E-03	0.280				Yes
Cadmium	3.76E+02	2.80E+00	1.17E-01	0.370				Yes
Chromium VI	4.47E+02	3.34E+00	1.39E-01		0.026			Yes
Manganese	6.18E+04	4.61E+02	1.92E+01		0.630			Yes
Mercury	9.39E+01	7.01E-01	2.92E-02		0.013			Yes
Nickel	3.60E+02	2.69E+00	1.12E-01		0.130			Yes
Organic Compounds:								
Acetaldehyde	3.51E+03	2.52E+01	1.05E+00				6.800	No
Acrolein	5.62E+02	4.03E+00	1.68E-01				0.020	Yes
Ammonia	6.18E+05	1.69E+03	7.05E+01				0.680	Yes
Benzene	4.30E+03	3.22E+01	1.34E+00	8.100				Yes
Benzo(a)Pyrene	2.43E-04	1.17E-05	4.87E-07	2.200				No
Butadiene, 1,3-	1.25E+03	9.34E+00	3.89E-01	11.000				Yes
Formaldehyde	6.23E+04	4.47E+02	1.86E+01				0.040	Yes
Sulfuric Acid	2.67E+05	9.63E+03	4.01E+02		0.250	0.025		Yes
Toluene	1.14E+04	8.19E+01	3.41E+00		98.000		14.400	No
Xylenes	5.62E+03	4.03E+01	1.68E+00		57.000		16.400	No

Based on the above, the Permittee is required to demonstrate compliance with AALs for arsenic, beryllium, cadmium, chromium (VI), manganese, mercury, nickel, acrolein, ammonia, benzene, 1,3-butadiene, formaldehyde, and sulfuric acid.

The Permittee has performed the modeling analysis for these pollutants on a source-by-source basis and the resulting modeled concentrations are compared to the applicable AALs. The highest potential to emit emission rates for emissions sources emitting the pollutants are utilized. Specifically, for the proposed combustion turbine, the highest potential to emit emission rate from natural gas and fuel oil burning for each pollutant is used. In addition, even though the combustion turbine is not expected to operate continuously (24 hours day, 365 days per year) to comply with the non-base load operation standard in NSPS Subpart TTTT, the modeling analysis for all averaging periods conservatively assumed 8760 hours of operation for the combustion turbine. For all existing sources, modeled emissions rates are derived assuming 8,760 hours per year facility operations. The modeling establishes optimized, maximum-allowable emission limits for each TAP on a source-by-source basis. The optimized emission rates correspond to up to 98 percent of applicable AALs. The following Tables 4-4 and 4-5 provide the optimized emissions rates, proposed for approval, and the predicted maximum impacts.

Table 4-4: Air Toxics Limits

Emission Source	Pollutant Emission Limit (lb/hr)														
	Averaging Period														
	Acrolein (lb/hr)	Ammonia (lb/hr)	Arsenic (lb/hr)	Benzene (lb/hr)	Beryllium (lb/hr)	1,3-Butadiene (lb/hr)	Cadmium (lb/hr)	Soluble Chromate Compounds, as Chromium (VI) Equivalent (lb/hr)	Non-specific Chromium (VI) Compounds (lb/hr)	Formaldehyde (lb/hr)	Manganese (lb/hr)	Mercury (lb/hr)	Nickel (lb/hr)	Sulfuric Acid (lb/hr)	Sulfuric Acid (lb/hr)
	1-hour	1-hour	Annual	Annual	Annual	Annual	Annual	24-hour	Annual	1-hour	24-hour	24-hour	24-hour	1-hour	24-hour
ES-1	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-2	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-3	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-4	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-5	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-6	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-7	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-8	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-9	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-10	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-11	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-12	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-13	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-14	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-15	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-16	2.82E+01	--	6.45E-02	3.50E-02	8.25E-02	1.23E+01	1.84E-01	2.60E+00	2.64E-03	7.60E+01	1.30E+02	2.52E+00	2.52E+01	5.16E+01	5.17E+01
ES-19, gas firing	1.12E+02	8.41E+04	--	--	--	--	--	--	--	3.03E+02	--	--	--	5.00E+00	5.00E+00
ES-19, oil firing	--	--	9.92E-01	5.38E-01	1.27E+00	1.89E+02	2.83E+00	9.13E+00	4.06E-02	--	4.56E+02	8.81E+00	8.81E+01	--	--
I-18	8.02E-01	--	1.21E-05	3.09E-04	4.14E-04	1.56E-02	5.98E-05	1.17E-04	7.21E-07	2.50E-01	8.57E-05	5.44E-04	1.42E-03	--	--
ES-17	--	--	--	3.04E-03	--	--	--	--	--	--	--	--	--	--	--
ES-18	--	--	--	3.04E-03	--	--	--	--	--	--	--	--	--	--	--
ES-20	--	--	--	3.14E-04	--	--	--	--	--	--	--	--	--	--	--

Table 4-5: Maximum Modeled Impacts

Pollutant	Averaging Period	Maximum Modeled Impacts % of AAL
Acrolein	1-hour	98.00 %
Ammonia	1-hour	98.13 %
Arsenic	Annual	94.81 %
Benzene	Annual	44.09 %
Beryllium	Annual	98.78 %
1,3-Butadiene	Annual	96.35 %
Cadmium	Annual	94.55 %
Chromium VI, Soluble	24-hour	97.89 %
Chromium VI, Total	Annual	84.34 %
Formaldehyde	1-hour	98.01 %
Manganese	24-hour	98.17 %
Mercury	24-hour	98.34 %
Nickel	24-hour	98.04 %
Sulfuric Acid	1-hour	97.95 %
	24-hour	97.97 %

Although the air toxic emissions from fuel oil storage tanks and the sources subject to Part 63 standards (simple cycle combustion turbines subject to Subpart YYYY and fire pump engine subject to Subpart ZZZZ) are exempt from air toxics permitting pursuant to 02Q .0702(a)(19)(B) and 02Q .0702(a)(27)(B), respectively, the Permittee has volunteered to include emissions of all such exempt sources for compliance purposes.

The DAQ has verified the emissions factors and the methodology used to estimate emissions rates, and found them to be satisfactory. The Air Quality Analysis Branch (AQAB) has reviewed the dispersion modeling analysis for the facility and concluded on April 4 and 17, 2018, that the submitted modeling analysis adequately demonstrates compliance on a source-by-source basis.

The North Carolina Division of Air Quality's air toxics program is a "risk-based" regulatory program designed to protect the public health by limiting the emissions of toxic air pollutants from man-made sources. Because the analysis did demonstrate compliance on a source-by-source basis including emissions of exempt sources with the applicable AALs, the DAQ has concluded that the emissions from the exempt Part 63 affected sources, such as simple cycle combustion turbines and fire pump engine, or other exempt sources such as fuel oil storage tanks, will not present an unacceptable risk to human health based on dispersion modeling analysis. The revised permit will not include approved air toxics emissions rates for the exempt sources as all emissions for each of these pollutants are from the exempt sources.

Cross-State Air Pollution Rule

The first legally-survived[11] “transport rule”, pursuant to the “good neighbor” provision in CAA § 110(a)(2)(D)(i), covers the down-wind states for non-attainment and maintenance of 1997 ozone and $PM_{2.5}$ NAAQSs, and 2006 $PM_{2.5}$ NAAQS. This regulation includes ozone season and annual NOx requirements, and annual SO_2 requirements, for power sector electric generating units in various eastern USA (total 28 states). The transport rule is also called the Cross-State Air Pollution Rule (CSAPR). The requirements are codified in 40 CFR 97, Subparts AAAAA, BBBBB, and CCCCC.

The proposed combustion turbine is subject to the CSAPR requirements as NC is one of the subject 28-states. However, the CSAPR is a federal implementation plan; therefore, DAQ will include the applicability for this regulation in the permit without any substantive requirements, as “federal-only”. It needs to be noted that the compliance with the CSAPR will be determined by the EPA and not the DAQ.

Finally, it should be stated that the EPA has also issued a CSAPR Update rule for ozone season NOx, covering the 2008 ozone NAAQS for 22 (eastern and midwestern) US states. This regulation (again a FIP) does not apply to NC.

5.0 BACT Analysis

Background

The CAA §169(3) defines:

> “The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to enactment of the federal Clean Air Act Amendments of 1990.”

Given the variation between emission sources, facility configuration, local air-sheds, and other case-by-case considerations, Congress determined that it was impossible to establish a single BACT determination for a particular pollutant or source. Economic, energy, and environmental impacts are mandated in the CAA to be considered in the determination of case-by-case BACT for specific emission sources. In most instances, BACT may be defined through an emission limitation. In cases where this is impracticable, BACT can be defined using a particular type of control

[11] Slip Opinion, *EPA v. EME Homer City Generation L.P.*, Supreme Court of the United States, April 29, 2014.

device, work practice, or fuel type. In no event, can a technology be recommended which would not comply with any applicable standard of performance under CAA §§111 (NSPS) or 112 (NESHAP).

The EPA developed guidance, commonly referred to as "Top-Down" BACT[12], for PSD applicants for determining BACT. This guidance is a non-binding reference material for permitting agencies, which process PSD applications pursuant to their SIP-approved regulations. As stated in Section 4.0 above, NCDAQ issues PSD permits in accordance with its SIP-approved regulation in 15A NCAC .02D .0530. Therefore, the DAQ does not strictly adhere to EPA's "top-down" guidance. Rather, it implements BACT in accordance with the statutory and regulatory language. As such, NCDAQ's BACT conclusions may differ from those of the EPA.

As stated above, a major modification review is triggered for the project due to increases in emissions of PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC, and GHG. Thus, each emissions unit undergoing physical or operation change (i.e., new simple cycle combustion turbine and fuel oil storage tank) where the net emissions increase is projected to occur, is required to apply BACT for these pollutants, as per §51.166(j)(3).

The emissions unit must be defined so that the BACT analysis can be performed. In this case, the project's purpose is to develop, commercialize, and operate an advanced, natural gas/No. 2 fuel oil-fired simple cycle combustion turbine, which is to be supported by a new, No. 2 fuel oil storage tank. The new turbine is to principally burn natural gas. However, for emergencies, for example, if there is any physical interruption in natural gas delivery to the facility or if there is a temporary spike in the market price of natural gas that makes the fuel oil more economical, the unit will also have the capability to burn No. 2 fuel oil (ULSD). It is clear that these fuel choices (natural gas with back up No. 2 fuel oil) for the new combustion turbine are integral to the project's purpose/objectives and DAQ firmly believes that BACT cannot be used to regulate project's purpose or facility's design. However, at the same time, it "does not prevent the permit issuer [such as DAQ] from taking a "hard look" at whether the proposed facility may be improved to reduce its pollutant emissions."[13]. "Clean fuels[14] [e.g., natural gas, low-sulfur fuel oil] are an available means of reducing emissions to be considered along with other approaches in identifying BACT approaches."[15] Moreover, "clean fuels [provision] may not be "read out" of the Act merely because their use requires "some adjustment" to the proposed technology [and] if the only required adjustment were that a dirtier fuel be "switched" to a cleaner fuel…then the low sulfur coal should be the BACT choice over high sulfur coal."[16] In summary, BACT analysis for the proposed project needs to be performed for natural gas/fuel oil-fired simple cycle combustion turbine and fuel oil storage tank, considering the approach outlined here.

Emissions Profile of Proposed Combustion Turbine v. RBLC Data

As stated elsewhere, the proposed combustion turbine is yet to be developed (commissioned, tested and validated) before it can be commercially available. Hence, its emissions profile is expected to be much different in the developmental stage than the commercially available simple cycle combustion turbine of a similar size and fuel firing. Specifically, emissions profile is expected to vary among various stages of development in each configuration: commissioning, testing and validation phases. Further, any BACT control which may be required, are not expected to be operational during the commissioning phase of each configuration. For example, operation of any catalyst (for NOx or CO control) can foul the expensive catalyst materials. Moreover, any external control device's effectiveness can be limited during testing phase in each configuration due to operational variability, such as multiple startups, shutdowns, and load changes. Therefore, BACT determination for the proposed turbine are expected to be different than a similar commercially available combustion turbine.

---

[12] "Improving New Source Review (NSR) Implementation", J. Craig Potter, Assistant Administrator for Air and Radiation US EPA, Washington D.C., December 1, 1987, and "Transmittal of Background Statement on "Top-Down" Best Available Control Technology", John Calcagni, Director, Air Quality Management Division, US EPA, OAQPS, RTP, NC, June 13, 1989.
[13] In Re Prairie State Generating Company, PSD Appeal No. 05-05, 13 E.A.D. 1. (EAB, August 24, 2006).
[14] Definition of BACT at CAA §169(3).
[15] In Re Inter-Power of New York, Inc., PSD Appeal Nos. 92-8 and 92-9, Final Order, 5. E.A.D. 130 (EAB, March 16, 1994).
[16] Slip Opinion, *Sierra Club v. US EPA and Prairie State Generating Company LLC (Intervenor)*, No. 06-3907, United States Court of Appeals for the Seventh Circuit, Decided August 24, 2007.

With respect to availability of state/local agencies' determinations under various CAA programs (such as Reasonably Available Control Technology [RACT], Best Available Control technology [BACT], Lowest Achievable Control Technology [LAER]) for different pollutants for simple cycle combustion turbines with similar equipment development profiles, the applicant has stated that it has reviewed the RBLC[17] data, but, has not found any determination with such equipment development profile for a non-commercially available combustion turbine. Nevertheless, when establishing BACT for pollutants triggered for the proposed turbine, BACT determinations of a similar commercially available combustion turbine have been reviewed and taken into consideration. Specifically, the DAQ has reviewed the RBLC data for time-period (2012-present) for natural gas and fuel oil fired simple cycle combustion turbines. DAQ believes that the data provides relevant information on BACT determinations from various permitting authorities in recent years to help determine the type of technology and/or associated limitation for units with similar design (natural gas/No. 2 fuel oil fired simple cycle combustion turbines) and electric power output capacity greater than 25 MW. The Permittee has reviewed the same database for a longer period (2006 through present) to capture more determinations for the same kind of combustion turbines.

BACT Analysis for CO

CO emissions are generated due to incomplete conversion of carbon-containing compounds to CO_2 and water during fuel combustion. CO emissions are principally related to turbine operating conditions, such as lower than optimal combustion temperature, insufficient combustor residence time, and turbine operating load.

<u>CO Control Alternatives</u>

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after it is formed in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the turbine exhaust, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Oxidation of CO to CO_2 utilizes the excess oxygen present in the turbine exhaust; the activation energy required for the oxidation reaction to proceed is lowered in the presence of the catalyst. 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 and sulfuric acid mist emissions.

CO catalytic oxidation reactors operate in a relatively narrow temperature range. At lower temperatures, CO conversion efficiency falls off rapidly. At higher temperatures, catalyst sintering may occur; thus, causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust point and proper operating temperature considering the temperature variations that are expected to occur across the unit's operating load range. Operation at part load or during start-up/shutdown will result in less than optimum temperatures and reduced control efficiency.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the costliest part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

Catalytic oxidation is considered to be a technically feasible option for the proposed simple cycle combustion turbine with control efficiency between 80 to 90 percent when burning natural gas. No data are available for oxidation catalysts' control efficiency when burning fuel oil. CO catalysts are also expected to reduce emissions of VOCs and HAPs.

[17] RACT/BACT/LAER Clearinghouse.

Good Combustion Practices

As previously stated, CO is formed during the combustion process because of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Proper combustor design and optimization of the combustion air feed systems to achieve good combustion efficiency will minimize the generation of CO emissions from combustion turbines.

Good combustion control is concluded to be a technically feasible option for the proposed combustion turbine. Due to high combustion efficiency of combustion turbines (near 99 percent), CO emissions are inherently low.

Energy, Environmental, and Economic Impacts

An oxidation catalyst system does provide a negative impact on combustion turbine performance related to the backpressure the system imposes on the turbine. In addition, the catalyst material itself has a functional lifetime and must be periodically regenerated or replaced. Overall, however, the economic and energy impacts resulting from operation of an oxidation catalyst system on the proposed turbine may not be significant. There are no adverse economic or energy impacts associated with the use of good combustion practices.

With respect to environmental impact, the use of an oxidation catalyst system on the proposed turbine is expected to result in a slight increase in sulfuric acid emissions caused by the oxidation of a portion of the unit's SO_2 emissions to SO_3 and the subsequent reaction of SO_3 with water vapor to form sulfuric acid. This increase is small in comparison to the decrease in CO emissions that will result from the use of the oxidation catalyst system. The catalyst must also be regenerated periodically and must be disposed of or recycled at the end of its useful life, which has some but minimal environmental impact. There are no adverse environmental impacts associated with the use of good combustion practices.

BACT Determination

The DAQ review of the RBLC data for the selected timeframe (2012-present) indicates a total of 26 determinations for natural gas firing scenario and one determination for No. 2 fuel oil firing scenario.

Out of 26 determinations for natural gas scenario, 5 determinations include oxidation catalyst and the remaining 21 determinations require good combustion control for CO emissions. Majority of determinations (15) include emissions limit of 9 ppm. The minimum emission limit is 1.5 ppm (using oxidation catalyst in a LAER determination) and the maximum limit is 25 ppm.

With respect to oil firing, the determination includes a BACT of 20 ppm using good combustion control.

Tables 1 and 2 in Appendix A provide the above DAQ findings.

DEC has proposed a BACT of 10 ppmvd at 15% O_2 (30-day average), using good combustion control practices for both natural gas and oil firing scenarios, based upon the vendor guaranteed limit of 10 ppm. The applicant has argued, as stated above, that the use of oxidation catalyst is not technically feasible during commissioning phase and meeting a lower emission limit (lower than 10 ppm) is also not technically feasible during testing phase of each configuration. In addition, the emission rates during startups and shutdowns are expected to be somewhat higher than the normal operations. The applicant has requested flexibility for the use of an oxidation catalyst for determining whether it would be necessary to install an oxidation catalyst to comply with the BACT. Finally, compliance is to be determined using a continuous emission monitoring system (CEMS).

DAQ agrees with the applicant that the use of any add-on control device such as catalytic oxidation is not feasible during the commissioning phase. DAQ also agrees that the effectiveness of the oxidizer will be limited during the testing phase due to frequent startups, shutdowns, and load swings. Thus, DAQ agrees with the applicant that a lower limit (lower than 10 ppm) as BACT is not feasible for the proposed combustion turbine on a continuous basis during the developmental phases (commissioning, testing, and validation) of each of the configurations (Versions A, B, and C). Therefore, DAQ proposes to approve a BACT of 10 ppmvd at 15% O_2, using good combustion control, for both natural gas and fuel oil firing scenarios. This BACT applies during all periods of operations, including normal operations, and startup, shutdown and malfunction events. The applicant will be allowed to determine whether the use of oxidation catalyst is necessary to achieve compliance during the developmental phases of each configuration. The compliance with the BACT will be determined using a CEMS on a 24-hour rolling basis. The DAQ believes that the shorter averaging time with somewhat less stringent limit of 10 ppm (v. 9 ppm in the majority of RBLC determinations) is reasonable.

The manufacturer of the equipment (Siemens) has also indicated a lower emission limit of 4 ppmvd @ 15% O_2 for both natural gas and fuel oil firing scenarios, with the expectation of use of oxidation catalyst (compared to 10 ppmvd @ 15% O_2 presumably without the oxidation catalyst as above) for different load points (35 percent to base load for natural gas and 70 percent to base load for fuel oil). The DAQ, thus, believes that this lower limit of 4 ppm is achievable with the use of an oxidation catalyst on a continuous basis during commercial operation. Thus, DAQ proposes to establish a BACT of 4 ppmvd @ 15% O_2 with the use of oxidation catalyst, for both natural gas and oil firing scenarios, upon commencement of commercial operation. The DAQ believes that this more stringent BACT is reasonable for CO, especially upon start of commercial operation, as the unit would have completed all commissioning/testing/validation for each of the configurations and it would be technically feasible to operate the oxidation catalyst. At least for natural gas firing, it should also be noted that this proposed 4 ppm BACT is similar to other BACT determinations for natural gas fired simple cycle combustion turbines, as discussed above. Specifically, after excluding the most stringent determination of 1.5 ppm[18], the next higher BACT level is 4 ppm; because it is unknown whether the 1.5 ppm limit has been achieved in practice at the facility associated with this determination. The BACT applies during all periods of operations, including normal operations, and startup, shutdown and malfunction events. The compliance with the BACT will be determined using a CEMS on a 24-hour rolling basis.

BACT Analysis for VOC

VOC emissions from combustion turbines are attributable to the same factors as described for CO emissions above. VOC emissions result from incomplete combustion of carbon compounds in the fuel, which is influenced primarily by the temperature and residence time within the combustion zone.

<u>VOC Control Alternatives</u>

As described above, an oxidation catalyst is a post-combustion technology that oxidizes products of incomplete combustion in the turbine exhaust. VOC compounds will react with residual oxygen in the presence of a catalyst, producing carbon dioxide and water vapor. The performance of an oxidation catalyst system is dependent on the specific VOC constituents present in the turbine exhaust.

Catalytic oxidation is considered to be a technically feasible option for the proposed simple cycle combustion turbine with control efficiency between 80 to 90 percent when burning natural gas. No data are available for oxidation catalysts' control efficiency when burning fuel oil.

Good Combustion Practices

As previously discussed, VOCs are formed during the combustion process because of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time within the turbine combustor will minimize the formation of VOCs.

Good combustion control is concluded to be a technically feasible option for the proposed combustion turbine. Due to high combustion efficiency of combustion turbines (near 99 percent), VOC emissions are inherently low.

<u>Energy, Environmental, and Economic Impacts</u>

As stated previously, an oxidation catalyst system does provide a negative impact on combustion turbine performance related to the backpressure the system imposes on the turbine. In addition, the catalyst material itself has a functional lifetime and must be periodically regenerated or replaced. Overall, however, the economic and energy impacts

[18] Cove Point LNG Terminal, Permit Issuance Date 6/9/2014, MD-0044.

resulting from operation of an oxidation catalyst system on the proposed turbine may not be significant. There are no adverse economic or energy impacts associated with the use of good combustion practices.

Also, as described above, a slight increase in sulfuric acid emissions can be expected to occur in conjunction with the use of an oxidation catalyst system. The catalyst must also be regenerated periodically and must be disposed of or recycled at the end of its useful life, which has some but minimal environmental impact. Also noted above, there are no adverse environmental impacts associated with the use of good combustion practices.

BACT Determination

The DAQ review of the RBLC data indicates a total of 11 determinations for natural gas firing scenario and only one determination for No. 2 fuel oil firing scenario exist for the selected timeframe (2012-present).

Out of 11 determinations for natural gas scenario, 2 determinations include oxidation catalyst and the remaining 9 determinations require good combustion control for VOC emissions. A number (4) of the determinations include emission limit of 2 ppm. The minimum emission limit is 0.7 ppm associated with catalytic oxidation, which is a LAER. Three determinations include BACT in the form of pound per hour and no information for each is available to convert the limits in ppm of pollutant for a comparison with other BACT determinations which are in the form of ppm of pollutant.

With respect to oil firing, the determination includes a BACT of 3.3 lbs/hr, using good combustion control.

Tables 3 and 4 in Appendix A provide the above DAQ findings.
DEC has proposed a BACT of 3 ppmvd at 15% O_2 (24-hour average), using good combustion control practices for both natural gas and oil firing scenarios. This applicant-proposed BACT is based upon the vendor guaranteed limit of 3 ppm. The applicant has argued that the use of oxidation catalyst is not technically feasible during commissioning and testing phases, and meeting any lower emission limit (lower than 3 ppm) is also not technically feasible. In addition, the emission rates during startups and shutdowns are expected to be somewhat higher than the normal operations. The applicant has proposed to conduct stack testing to determine whether an oxidation catalyst is necessary to comply with the BACT. If oxidation catalyst is not necessary to demonstrate compliance with the BACT, compliance will be determined using stack testing. If an oxidation catalyst is necessary to meet the BACT limit, it is proposed that the turbine exhaust temperature at the inlet to the oxidation catalyst is to be monitored continuously.

DAQ agrees with the applicant that use of any add-on control device such as catalytic oxidation is not feasible during both the commissioning and testing phases. DAQ also agrees that the effectiveness of oxidizer will be limited during the testing phase due to frequent startups, shutdowns, and load swings. Thus, DAQ agrees with the applicant that a lower than 3 ppm as BACT is not feasible for the proposed combustion turbine on a continuous basis during the equipment developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B, and C). Therefore, DAQ proposes to approve a BACT of 3 ppmvd at 15% O_2, for both natural gas and fuel oil firing scenarios. The BACT applies during all periods of operations (normal operations, and startup, shutdown and malfunction events). The applicant will be allowed to determine whether the oxidation catalysis will be needed to achieve compliance. Compliance with the BACT will be determined as an average of 3 stack test runs. If an oxidizer is determined to be required for compliance, the applicant will also be continuously measuring exhaust temperature to the inlet to the oxidizer.

The manufacturer of the equipment has also indicated a lower emission limit of 2 ppmvd @ 15% O_2 for both natural gas and fuel oil firing scenarios, with the expectation of use of oxidation catalyst (compare to 3 ppmvd @ 15% O_2 presumably without the oxidation catalyst as above) for different load points (35 percent to base load for natural gas and 70 percent to base load for fuel oil). The DAQ believes that this lower limit of 2 ppm is achievable with the use of oxidation catalyst on a continuous basis during commercial operation. Thus, DAQ proposes to establish a BACT of 2 ppmvd @ 15% O_2 with the use of oxidation catalyst, for both natural gas and oil firing scenarios, upon commencement of commercial operation. The same oxidation catalyst, used for CO BACT during the commercial operation, will help meet this lower VOC BACT during commercial operation as a co-benefit. The DAQ believes that this more stringent BACT is reasonable for VOCs, especially upon start of commercial operation, as the unit would have completed all required commissioning/testing/validation for each of the configurations and it would be technically feasible to operate the oxidation catalyst. From a natural gas firing standpoint, it should be noted that this proposed 2 ppm BACT is similar to other BACT determinations for natural gas fired simple cycle combustion turbines, as discussed above. Specifically, after excluding the most stringent BACT of 0.7 ppm[19] (associated with a LAER) and the next higher BACT level of 1.4 ppm[20] (unknown whether this limit was achieved in practice), the next higher limit is 2 ppm. The BACT applies during all periods of operations, including normal operations, and startup, shutdown and malfunction events. Compliance with the BACT will be determined as an average of 3 stack test runs.

BACT Analysis for NOx

NOx emissions result from combustion turbine operation in two ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NOx); and 2) the oxidation of nitrogen contained in the fuel (fuel NOx). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen; therefore, NOx emissions from natural gas fired combustion turbine generators originate as thermal NOx only. The rate of formation of thermal NOx is a function of residence time and free oxygen concentration, and increases exponentially with increasing peak flame temperature. Fuel oil contains trace levels of fuel bound nitrogen that will contribute to NOx emissions.

"Front end" NOx control techniques are aimed at controlling thermal NOx and/or fuel NOx. The primary front-end combustion controls for combustion turbine systems include water or steam injection into the combustor, and specific combustor design features. The addition of an inert diluent such as water or steam into the high temperature region of the combustor decreases NOx formation by quenching peak flame temperature. Dry low-NOx combustors limit peak flame temperature and excess oxygen with lean, pre-mix flames that decrease NOx formation to levels that are equal to or better than achieved via water or steam injection when burning natural gas.

Catalytic combustion is an emerging front-end technology which uses an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low thermal NOx formation. Other control methods, known as "back-end" controls, remove NOx from the exhaust gas stream once NOx has been formed.

<u>NOx Control Alternatives</u>

Selective Catalytic Reduction

SCR is a process which involves post combustion removal of NOx from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$
$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O$
$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H2O$
$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$
$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reactions. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the NH_3 injection system, and high NH_3 slip.

The NOx reduction reactions take place within the temperature range of 650 to 850°F. The exhaust temperature of simple cycle turbines is typically higher than this range, so some means to reduce the temperature of the turbine exhaust must be utilized for SCR to be technically feasible on this source type. In this case, the proposed turbine will utilize dilution with ambient air to reduce the temperature of the turbine exhaust before it is introduced into the SCR reactor.

[19] Cove Point LNG Terminal, Permit Issuance Date 6/9/2014, MD-0044.
[20] Roanoke Prairie Generating Station, Permit issuance Date 9/22/2014, TX-0696, and Shawnee Energy Center, Permit Issuance Date 10/9/2015, TX-0768.

SCR is a technically feasible option that represents the state-of-the-art NOx control for simple cycle combustion turbines.

Dry Low-NOx Combustors

Combustion control techniques that utilize design and/or operational features of the turbine's combustors which reduce NO_X emissions without injecting an inert diluent (water or steam) are generically referred to as "dry" Low NOx (DLN) measures. The particular features of a DLN combustor design are vendor-specific, but generally DLN combustors seek to reduce thermal NOx formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen. Alternatives include combustion distribution over several burner stages and pre-mixing air and fuel prior to injection into the combustion zone. These measures produce a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors. DLN combustors have been employed successfully on natural gas-fired combustion turbines for more than fifteen years. DLN combustors are technically feasible on the proposed unit.

Water or Steam Injection

Water and steam injection involves the injection of water or steam into the high temperature region of the combustor flame. These alternatives also seek to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NOx formation.

Although water and steam injection have been employed successfully for nearly thirty years on combustion turbines, this alternative greatly reduces the turbine's efficiency. With the ambitious efficiency targets now mandatory for new combustion turbine units in order to control CO_2 emissions, water or steam injection as a means to control NOx emissions is no longer considered state of the art.

<u>Energy, Environmental, and Economic Impacts</u>

There are economic and energy impacts associated with the use of SCR and DLN combustors on the proposed combustion turbine, but these impacts are not considered to be sufficiently adverse to disqualify these alternatives as BACT candidates.
The use of water injection to control formation of NOx would have a significant effect on the energy efficiency of the unit. For this reason, and because lower NOx emission rates can be achieved using SCR in conjunction with DLN combustors than with SCR in combination with water injection, water injection is eliminated as a BACT candidate.

In applications employing SCR, an excess of ammonia must be injected into the turbine exhaust in order to achieve low NOx emission rates. This creates two forms of adverse environmental impacts. Ammonia that is not consumed in the SCR reactor is discharged to the atmosphere as ammonia slip, and excess ammonia can react with SO_2 and SO_3 in the turbine exhaust to form ammonium salt compounds (ammonium sulfate and ammonium bisulfate) which are discharged as particulate matter.

In addition, the use of an SCR can be expected to increase the formation of sulfuric acid emissions by the oxidation of a portion of the turbine's SO_2 emissions to SO_3 and the subsequent reaction of SO_3 with water vapor to form sulfuric acid.

There are no adverse environmental impacts associated with the DLN combustors.

<u>BACT Determination</u>

The DAQ review of the RBLC data indicates that there are total 26 determinations for natural gas firing scenario and only one determination for No. 2 fuel oil firing scenario.

Out of 26 determinations for natural gas scenario, 19 determinations included BACT of 9 ppm. The most stringent BACT was 2.5 ppm with the next higher limit of 5 ppm. The associated control technologies were DLN (23 times), SCR (5 times), water injection (2 times), and good combustion control (1 time). The lower limits (2.5 ppm, 5 ppm) are associated with the use of SCR for either lowest achievable emission rates (LAER) determinations (under non-attainment area NSR program), combined cycle units, or aero-derivative CT technology (significantly smaller CT units, ~45-100 MW). Finally, two determinations included BACT in the form of a pound per hour limit. However, no information for each is available to convert the limits in ppm of a specific pollutant for a comparison with other BACT determinations which are in the form of ppm of a specific pollutant.

With respect to oil firing, the determination includes a BACT of 42 ppm using DLN and water injection.

Tables 5 and 6 in Appendix A provide the above DAQ findings.

DEC has proposed for the validation phase of each configuration the BACT of 9 ppmvd @ 15% O_2 (4-hour rolling average) for natural gas firing and 12 ppmvd @ 15% O_2 (4-hour rolling average) for distillate oil firing, using diluent SCR in combination with operation of DLN combustors.

For commissioning and testing phases, DEC has proposed 45 ppmvd @ 15% O_2 (4-hour rolling average) using DLN combustors alone as BACT.

A CEMS for NOx will be used to demonstrate compliance with these BACT emission limits.

As stated previously, DEC has planned for commissioning and testing phases of each configuration without the use of SCR to protect the sensitive catalyst components; thus, it has proposed a higher limit of 45 ppm as per the equipment manufacturer (Siemens).

With respect to validation phase of each configuration, DEC has stated that in combined cycle combustion turbines, SCRs are typically located downstream of the heat recovery steam generator (HRSG), which allow protection of catalyst media from high exhaust temperatures and flow variations. But, unlike combined cycle units, no such protections are expected to be available for SCRs on simple cycle combustion turbines. Therefore, the applicant argues that the variations in combustion turbine exhaust temperature and flow need to be compensated by changing the output of the dilution air/tempering fans. Considering the time delay associated with such controls, the applicant believes that the expected NOx control effectiveness of dilution SCR systems is less than SCR systems in combined cycle application. Per Siemens, the dilution SCR is expected to provide a reduction of approximately 85 percent for emissions from the proposed combustion turbine as compared to traditional SCRs on combine cycle units. Finally, the Permittee contends that none of the simple cycle turbine units in the RBLC are listed as employing a dilution air SCR system; thus, concluding that the configuration of the proposed system for this project is fundamentally different than those indicated in the RBLC listings for combustion turbines.

The DAQ believes that due to technical factors cited by the applicant, higher than 85 percent reduction efficiency is not expected for the dilution SCR on the proposed combustion turbine; thus, DAQ agrees that lower BACT (lower than 9 ppm for natural gas, 12 ppm for fuel oil) are not possible. Thus, DAQ proposes to establish a BACT of 9 ppmvd @ 15% O_2 (4-hour rolling average) for natural gas firing and 12 ppmvd @ 15% O_2 (4-hour rolling average) for distillate oil firing, for validation phase of developmental program and commercial operation (after the completion of development program). These BACT are to be achieved using diluent SCR in combination with DLN combustors. For commissioning and testing phases, DAQ proposes a BACT of 45 ppmvd @ 15% O_2 (4-hour rolling average) using DLN combustors alone, considering the limitations stated by the applicant. All proposed BACTs apply during all periods of operation, including normal operation, and startup, shutdown and malfunctions events. Compliance will be determined using CEMS.

BACT Analysis for PM / PM_{10} / $PM_{2.5}$

Particulate matter emissions from combustion turbines are a combination of filterable (front-half) and condensable (back-half) particles. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which are to be aggregated with filterable particulate matter when quantifying PM_{10} and $PM_{2.5}$ emission rates, are attributable primarily to the formation of sulfates and possibly organic compounds. Only the filterable fraction of particulate matter is used to quantify PM emission rates, as stated above pursuant to NC's SIP-approved PSD regulation.

PM / PM_{10} / $PM_{2.5}$ Control Alternatives

When EPA promulgated the combustion turbine NSPS in Subpart GG, it recognized that "particulate emissions from combustion turbines are minimal". When this NSPS for Stationary Gas Turbines was promulgated in 1979, EPA recognized that particulate emissions from stationary gas turbines are minimal. The Agency further noted that particulate matter control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive.[21] Thus, the EPA did not promulgate any PM standards for combustion turbines.

Similarly, when EPA promulgated the combustion turbine NSPS in Subpart KKKK, it noted that particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas and emissions of PM are only marginally significant with distillate oil firing because of the lower ash content.[22] Again, EPA did not establish any PM standards for any combustion turbines.

Moreover, add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial natural gas- or distillate oil-fired combustion turbines. The use of ESPs and baghouses are considered technically infeasible, and do not represent an available control technology. It needs to be noted that the estimated combustion turbine exhaust particulate matter concentration provided by Siemens for this unit, including condensable particulate matter, is approximately 0.001 gr/dscf. This rate is an order of magnitude lower than the outlet performance specification (0.01 gr/dscf) of a typical baghouse or ESP.

The most stringent particulate control method demonstrated currently for natural gas-fired and fuel-oil fired combustion turbines is the use of low-ash and low-sulfur fuel.

Proper combustion and the firing of clean fuels (i.e., those with negligible or zero ash content and low sulfur content) is considered to be technically feasible for application to this project.

Energy, Environmental, and Economic Impacts

There are no adverse energy, economic and environmental impacts, associated with the use of good combustion control and clean fuels on the proposed combustion turbine.

BACT Determination

The DAQ review of the RBLC data indicates that a total of 43 determinations exist in the selected timeframe (2012-present) for PM / PM_{10} / $PM_{2.5}$ for natural gas firing scenario and only one determination for No. 2 fuel oil firing scenario.

The BACT varies from 5 lb/hr to 84 lbs/hr for natural gas firing. The BACT for the only fuel oil burning determination is 14 lb/hr. All determinations include good combustion control and use of pipeline quality natural gas. It needs to be clarified that particulate matter emissions typically vary with turbine make, model and heat input rate.

Tables 7 and 8 in Appendix A provide the above DAQ findings:

DEC has proposed a BACT of 20.9 lbs/hr for natural gas firing and 38 lbs/hr for fuel oil firing, using good combustion practices and clean fuels. These BACTs apply during all periods of operation (normal, startups, shutdowns, malfunctions) and all phases (commissioning, testing, validation) of each configuration, and during the commercial operation. These applicant-proposed BACTs have been based upon experience of the manufacturer, size of the combustion turbine, and vendor performance guarantee. The applicant also emphasizes the contribution of ammonium bisulfate salts and sulfuric acid mist (both in the form of PM), due to operation of SCR, in setting the BACT level.

After careful consideration, the DAQ proposes a BACT for PM_{10} / $PM_{2.5}$, as follows:

20.9 lb/hr for natural gas firing
38 lb/hr for fuel oil firing

[21] 44 FR 52798, September 10, 1979.
[22] 71 FR 38497, July 6, 2006.

Considering that regulated NSR pollutant PM is filterable portion of particulates only and only 60 percent of PM10 / PM2.5 as per the applicant, the DAQ proposes to establish BACT for PM as follows:

12.54 lb/hr for natural gas firing
22.80 lb/hr for fuel oil firing

These BACTs apply during all periods of operation (normal, startups, shutdowns, malfunctions) for all phases (commissioning, testing, validation) of each configuration and for commercial operation. The BACT are to be achieved with the use of clean fuels: natural gas and No. 2 fuel oil (ultra-low sulfur diesel fuel) and good combustion control. Compliance will be determined using a 3-run stack test.

BACT Analysis for GHG

GHGs are defined in 40 CFR 51.166(b)(48) as a single air pollutant, which is the aggregate group of six greenhouse gases: CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6.

CO_2, N_2O, and CH_4 are the principal GHGs that will be emitted from the combustion turbines burning natural gas. CO_2 emissions result from the oxidation of carbon in the fuel. Emissions of greenhouse gases (GHG) from combustion turbines are approximately 99.9% CO_2, which result from oxidation of carbon in the fuel. CH_4 emissions result from incomplete combustion, and N_2O emissions result primarily from low temperature combustion. Emissions of CH_4 and N_2O from the combustion turbines are extremely low and as a result, control options for these pollutants are not discussed.

EPA recommends that permit applicants and permitting authorities identify all "available" GHG control options that have the potential for practical application to the source under consideration. In the *PSD and Title V Permitting Guidance for GHGs* (EPA, 2011), EPA emphasizes two mitigation approaches for CO_2: energy efficiency and carbon capture and storage (CCS). This guidance also states that clean fuels, which would reduce GHG emissions be considered, while not fundamentally redefining the source.

<u>GHG Control Alternatives</u>

Carbon Capture and Sequestration (CCS)

CCS requires capture of CO_2 from the flue gas, drying and compression, transport, and long-term storage or conversion of CO_2. Research, Development, and Demonstration (RD&D) programs are being conducted by the U.S. Department of Energy (DOE) to reduce project uncertainty and improve technology cost and performance. The focus of CCS RD&D is twofold: (i) to demonstrate the operation of current CCS technologies integrated at an appropriate scale to prove safe and reliable capture and storage; and (ii) to develop improved CO_2 capture component technologies and advanced power generation technologies to significantly reduce the cost of CCS, in order to facilitate widespread cost-effective deployment of this technology in the future.

Existing federal programs are being used to deploy at least five to ten large-scale integrated CCS projects. These projects are intended to demonstrate a range of current generation CCS technologies applied to coal-fired power plants and industrial facilities.[23] To date, none of these projects have encompassed natural gas or distillate oil-fired combustion turbines. Although currently-available technologies could be used to capture CO_2 from new and existing fossil energy power plants, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application.

The U.S Department of Energy's National Energy Technology Laboratory (DOE-NETL) summarizes the process steps required for CCS as follows:

". . . Separating CO_2 from flue gas streams is challenging for several reasons:

[23] Report of Interagency Task Force on Carbon Capture and Storage at page 123, August 2010.

- CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute (psia)), which dictates that a high volume of gas must be treated;

- Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes;

- Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system."[24]

If CO_2 capture can be achieved at a power plant, the collected volume would need to be routed to a geologic formation capable of long-term storage. Due to the volume of CO_2 generated by the proposed project, the captured gas would need to be transported to a potential storage site via a pipeline. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

". . .The majority of geologic formations considered for CO_2 storage, deep saline or depleted oil and gas reservoirs, are layers of porous rock underground that are "capped" by a layer or multiple layers of non-porous rock above them. Sequestration practitioners drill a well down into the porous rock and inject pressurized CO_2. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration. Coal seams are another formation considered a viable option for geologic storage, and their storage process is a slightly different. When CO_2 is injected into the formation, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells. There are other mechanisms for CO_2 trapping as well: CO_2 molecules can dissolve in brine and react with minerals to form solid carbonates; or adsorb in the pores of the porous rock. The degree to which a specific underground formation is amenable to CO_2 storage can be difficult to discern . . ."[25]

The technical feasibility of the three steps needed to implement CCS is discussed below:

Capture and Compression - Although amine absorption technology has been applied for CO_2 capture in the petroleum refining and natural gas processing industries, it is not yet commercially available for power plant gas turbine exhausts, which have much larger flow volumes and low CO_2 concentrations. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirmed this conclusion in its recently completed report on the current status of development of CCS systems:

"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Because the CO_2 capture capacities used in current industrial processes are much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

CO_2 Transport - Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project, the large quantity of material generated would need to be transported to a facility capable of storing it. Geological formations suitable for long term storage must provide a depth below the ground surface that is sufficient to provide the temperatures and pressures needed to maintain CO_2 in a supercritical state. Other factors such as a low permeability cap rocks and host rocks that can provide for the formation of stable minerals or the presence of deep saline formations are also required. The USGS is conducting studies to identify suitable geologic formations in the Eastern United States, but has not completed the work. The most promising formations appear to be in Southwest Virginia[26], far from the proposed project. A pipeline suitable for transporting CO_2 from the Lincoln County site is not currently available, thereby making CCS infeasible for this project.

CO_2 Storage - Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS would still depend on the

[24] NETL: Carbon Sequestration - Core R&D http://www.netl.doe.gov/technologies/carbon_seq/corerd/corerd.html
[25] Id. At 19.
[26] Virginia Department of Mines, Minerals and Energy - Division of Geology and Mineral Resources.

availability of a sequestration site. Further research is needed to determine whether or not deep saline formations suitable for storage exist in reasonable proximity to the proposed project. As per the applicant, no suitable geologic formations or basins exist for long-term storage of CO_2 for the proposed project anywhere in North Carolina, based on 2015 Carbon Storage Atlas. Additionally, even if it is assumed that CO_2 could be transported economically to a sequestration site, there are potential environmental impacts that would still require assessment before CCS technology can be considered feasible. These include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine;
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water; and
- Risks to fresh water because of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water.

CCS is not technically feasible for the proposed project based on the factors noted above and because this technology has not been demonstrated in practice for a combustion turbine-based power plant.

Even if CCS was technically feasible, this technology could not be considered representative of BACT due to unacceptable cost and energy impacts. The US DOE has estimated that CCS applied to a combustion turbine-based power plant would more than double the total plant cost and increase the levelized cost of electricity by 45%.[27] The net result would be a cost effectiveness in excess of $100/ton of CO2 controlled.[28] In addition, CCS would consume 20% of the power plant energy output. The energy requirement of CCS is unacceptable and would result in increased emissions of NOx and other pollutants.

Low Carbon Fuels

GHG emissions from fuel combustion depend on the carbon content of the fuel. GHG emissions from firing the proposed fuels for this project (natural gas and distillate oil) are among the lowest contributors on a heat input basis. Use of low carbon or low emitting fuels is considered a technically feasible option.

Energy Efficiency

Modern combustion turbine-based power plants include many features designed to achieve very high fuel to electricity efficiencies. The proposed new advanced gas turbine power plant is expected to be among the most efficient simple cycle systems available.

There are several contributors to the high efficiency of the advanced combustion turbine. These include the use of a multistage axial compressor with advanced 3-dimensional blading, which reduces aerodynamic losses. The equipment will use improved materials of construction, including thermal barrier coatings, to protect the hot gas turbine components. Advanced technologies for blade cooling will allow the unit to operate with a high turbine inlet temperature, which will substantially increase the thermodynamic efficiency of the gas turbine process. The turbine section will have four stages, thereby resulting in optimized load distribution on each stage. A flow diffusor at the exhaust of the gas turbine will be used to reduce the velocity of the air leaving the unit. The diffusor also will recover a part of the turbine's kinetic energy which otherwise would be lost. Finally, the electrical generator that is proposed to be used will have a water-cooled stator and hydrogen cooled generator; these features will contribute to the plant efficiency by minimizing electromagnetic losses across the generator section.

Energy efficiency is considered a technically feasible option for GHG emissions from the proposed combustion turbine.

[27] http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_Rev2.pdf at Page 5.
[28] Report of the Interagency Task Force on Carbon Capture and Storage at Page 123 (Aug. 2010). http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

Energy, Environmental, and Economic Impacts

There is no adverse energy, economic and environmental impacts, associated with the use of low carbon fuels or energy efficiency on the proposed combustion turbine.

BACT Determination

The DAQ review of the RBLC data indicates that a total of eight determinations exist in the selected timeframe (2012-present) for GHG emissions from natural gas firing scenario and only one determination for No. 2 fuel oil firing scenario.

The BACT varies from 1,300 lb/MWh to 1,707 lb/MWh for natural gas firing. A few of the determinations also establish BACT using mass rate limits on a 12-month rolling basis for natural gas firing. The BACT for the only fuel burning determination is 1,434 lb/MWh. Most determinations include a combination controls: use of natural gas and ultra-low diesel fuels, high efficiency turbines, thermal efficiency, and good combustion practices. Few determinations do not specify the control method.

Tables 9 and 10 in Appendix A provide the above DAQ findings:

DEC has proposed a BACT of 120 lb CO_2 per million Btu when firing natural gas only and 120-160 lb CO_2 per million Btu for multi-fuels firing, using clean fuels (natural gas and ultra-low sulfur diesel) and proper design and operation of the combustion turbine. After careful consideration, the DAQ proposes a BACT for GHG, as follows:

- 120 lb CO_2 per million Btu when firing natural gas (more than 90 percent natural gas on a heat input basis on a 12-month rolling basis),

- 120-160 lb CO_2 per million Btu, for multi-fuel firing (i.e., 90 percent or less natural gas firing on a 12-month rolling basis), and

- 1,401,411 tons CO_2e per 12-month rolling average

These BACTs apply during all periods of operation (normal, startups, shutdowns, malfunctions) of all phases (commissioning, testing, validation) of each configuration and for commercial operation. The BACTs are to be achieved with the use of clean fuels: natural gas and No. 2 fuel oil (ultra-low sulfur fuel oil), and proper design and operation of combustion turbine. It should be emphasized that the above BACT meets the applicable NSPS in Subpart TTTT, as discussed above. Compliance will be determined by an EPA reference test method, as a 3-run average stack test. Emission rate determined during stack test will be used to monitor GHG emissions on 12-month rolling average basis on CO_2e basis.

BACT Analysis for VOC for No. 2 Fuel Oil Storage Tank

VOC emissions from No. 2 fuel oil storage are caused by working losses (changes in liquid level) and breathing or standing losses (evaporative losses attributable to changes in the temperature or pressure of the tank contents).

VOC Control Alternatives

DEC performed a search of RBLC to identify distillate fuel oil storage tanks permitted since 2007 with BACT determinations for VOC (Process Type Code 42.005). This search identified a total of 15 listings for distillate fuel oil or diesel storage tanks with BACT determinations for VOC. The emission control alternatives included in these RBLC listings are essentially pollution prevention practices consisting of use of a fixed roof tank, submerged fill, storage of low vapor pressure liquids, and conservation vents.

VOC emissions from a No. 2 fuel oil storage tank are typically controlled by very low vapor pressure of the material and use of conservation vents. The applicant argues that installation of a new add-on VOC control device is not feasible for control of such a low level of emissions (1.5 tons per year of VOC from new fuel oil storage tank). Further, the use of vapor balancing is not applicable to a No. 2 fuel oil tank with very low vapor pressure and low emissions; it would only be applicable to storage of a higher vapor pressure liquid such as gasoline. Thus, pollution prevention approaches are the only controls feasible for a storage tank with very low emissions. These practices include use of a light colored fixed roof tank, storage of only low vapor pressure No. 2 fuel oil, use of submerged fill, and use of a conservation vent. The applicant also contends that none of its existing No. 2 fuel oils storage tanks, located at LCTS are equipped with any add-on control devices for VOC emissions.

Energy, Environmental, and Economic Impacts

There is no adverse energy, economic and environmental impacts, associated with the use of pollution prevention techniques to control VOC emissions from a No. 2 fuel oil storage tank.

BACT Determination

The DAQ approves the applicant-proposed BACT of 1.4 tons per consecutive 12-months, using pollution prevention approaches (i.e., use of a light colored fixed roof tank, storage of only low vapor pressure No. 2 fuel oil, use of submerged fill, and a conservation vent). This BACT is based upon an annual throughput of 59.4 million gallons of No. 2 fuel oil. The applicant will be required to keep records of fuel oil throughput on a monthly basis to demonstrate compliance with the BACT.

BACT Summary

The following Table 5-4 summarizes the DAQ proposed BACT for the new simple cycle combustion turbine and a No. 2 fuel oil storage tank:

Table 5-1: BACT Summary

EMISSION SOURCE	POLLUTANT	BACT	CONTROL DESCRIPTION
Combustion Turbine (ID No. ES-19)	CO	10 ppmvd @ 15% O_2, 24-hour rolling average, using CEMS, natural gas or No. 2 fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during all developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B and C)] 4 ppmvd @ 15% O_2, 24-hour rolling average, using CEMS, natural gas or No. 2 fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during post-developmental operation]	Good combustion control Good combustion control and oxidation catalyst
Combustion Turbine (ID No. ES-19)	VOC as CH_4	3 ppmvd @ 15% O_2, 3 run stack test average, natural gas or No. 2 fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during all developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B and C)] 2 ppmvd @ 15% O_2, 3 run stack test average, natural gas or No. 2 fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during post-developmental operation]	Good combustion control Good combustion control and oxidation catalyst

EMISSION SOURCE	POLLUTANT	BACT	CONTROL DESCRIPTION
Combustion Turbine (ID No. ES-19)	NOx	9 ppmvd @ 15% O_2, 4-hour rolling average, using CEMS, natural gas firing 12 ppmvd @ 15% O_2, 4-hour rolling average, using CEMS, fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during developmental phase (validation only) of each configuration (Versions A, B and C) and post-developmental operation]	DLN and DSCR
		45 ppmvd @ 15% O_2, 4-hour rolling average, using CEMS, natural gas or No. 2 fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during developmental phases (commissioning and testing only) of each configuration (Versions A, B and C)]	DLN
Combustion Turbine (ID No. ES-19)	PM_{10} / $PM_{2.5}$	20.9 lb/hr, 3 run stack test average, natural gas firing 38.0 lb/hr, 3 run stack test average, fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during all developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B and C) and post-developmental operation]	use of clean fuels: natural gas and No. 2 fuel oil (ultra-low sulfur diesel with 15 ppm maximum fuel sulfur) and good combustion control
	PM[29]	12.54 lb/hr, 3 run stack test average, natural gas firing 22.80 lb/hr, 3 run stack test average, fuel oil firing [Includes all periods of operation (normal, startup, shutdown, and malfunction) during all developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B and C) and post-developmental operation]	use of clean fuels: natural gas and No. 2 fuel oil (ultra-low sulfur diesel with 15 ppm maximum fuel sulfur) and good combustion control

[29] Filterable only.

EMISSION SOURCE	POLLUTANT	BACT	CONTROL DESCRIPTION
Combustion Turbine (ID No. ES-19)	GHG	120 lb CO_2 per million Btu, 3 run stack test average, natural gas firing (more than 90 percent natural gas on a heat input basis on a 12-month rolling basis) 120-160 lb CO_2 per million Btu, 3 run stack test average, multi-fuel firing (i.e., 90 percent or less natural gas firing on a 12-month rolling basis) 1,401,411 tons CO_2e per 12-month rolling average [Includes all periods of operation (normal, startup, shutdown, and malfunction) during all developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B and C) and post-developmental operation]	use of clean fuels: natural gas and No. 2 fuel oil (ultra-low sulfur diesel with 15 ppm maximum fuel sulfur), and proper design and operation of combustion turbine
No. 2 Fuel Oil Storage Tank	VOC	1.4 tons per 12-month rolling average [Includes all periods of operation (normal, startup, shutdown, and malfunction)]	use of a light-colored fixed roof tank, submerged fill and a conservation vent, and storage of only low vapor pressure No. 2 fuel oil

6.0 Air Quality Analysis

§51.66(m)(1) requires that the major modification application for a PSD permit include an analysis of the ambient air quality of the area where the source is located for any regulated NSR pollutant exceeding the significant net emissions increase. This analysis is called "pre-application analysis" (generally called the "preconstruction monitoring" requirement). For pollutants with associated NAAQS, the application must include 1 year of continuous monitoring data from the date of the receipt of the complete application. The permitting agency may accept ambient monitoring data for a shorter duration but data cannot be for less than 4 months. For pollutants for which no NAAQS exist, the permitting authority can require an analysis containing such data as it determines appropriate to assess the ambient air quality in the area in which the source is located.

§51.66(m)(2) includes that the owner or operator of a major modification shall, after construction of such modification, conduct such ambient monitoring as the permitting authority determines is necessary to determine the effect emissions from the stationary source or modification may have, or are having, on air quality in any area. This monitoring is called "post-construction monitoring".

However, §51.166(i)(5) includes that permitting authority may exempt any major modification from the requirements of §51.166(m), with respect to monitoring for a specific pollutant, if net emissions increase of the pollutant from a modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m^3, 8-hour average;
Nitrogen dioxide - 14 ug/m^3, annual average;
$PM_{2.5}$ - 0 μg/m^3, 24-hour average;
PM_{10} -10 μg/m^3, 24-hour average;
Sulfur dioxide - 13 ug/m^3, 24-hour average;
Lead - 0.1 μg/m^3, 3-month average.
Fluorides - 0.25 μg/m^3, 24-hour average;
Total reduced sulfur - 10 μg/m^3, 1-hour average
Hydrogen sulfide - 0.2 μg/m^3, 1-hour average; and
Reduced sulfur compounds - 10 μg/m^3, 1-hour average

The above concentration values are called "significant monitoring concentrations (SMC)".

In addition, for ozone, no *de minimis* air quality level (i.e., SMC) has been provided. As per EPA, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data.

The same provision includes some more exemptions from this air quality analysis requirement (both "preconstruction monitoring" and "post-construction monitoring") for the source (i.e., applicant) as follows: (i) If any regulated NSR pollutant is not listed with the associated impact level (i.e., SMC), or (ii) the concentrations of the pollutant in the area that the major modification would affect is less than the associated SMC.

As stated above, this major modification review is for emissions of CO, VOC, NOx, PM, PM10, PM2.5, and GHG. As stated below in Section 7.0, the predicted air quality impact of CO, PM, and PM10 are much less than the associated impact level (SMC). For PM2.5, as per EPA, "applicant[~~s~~] will generally be able to rely on existing representative monitoring data to satisfy monitoring data requirement [i.e. the pre-pre-construction monitoring]".[30] Moreover, there are no SMC established for GHG so no ambient monitoring (both pre- and post-construction) for GHG can be required. Hence, no ambient monitoring (both pre- and post-construction) for CO, PM10, PM2.5, or GHG, may be required for this major modification.

For ozone NAAQS, the net significant emissions of VOCs and NOx are greater than 100 tons per year. Refer to Section 7.0 below for further details.

7.0 Source Impact Analysis

Introduction

The PSD ambient air quality modeling analysis reviewed in this report, in general, follows all applicable federal and state rules and modeling guidelines. Modeling methodologies and interpretation of results follows both the Class II and Class I modeling protocols submitted to NC DAQ on May 19, 2017 and the NC DAQ comments on the modeling protocols provided to Duke-Lincoln in a letter dated June 6, 2017. The modeling analysis also follows various email correspondence (August 2017 through January 2018) that provided NC DAQ clarifications on certain modeling assumptions, inputs and non-default regulatory modeling options.

A detailed description of the modeling methodology and inputs are described in the following sections.

Significant Emission Rate (SER) Analysis

As included on page 1 of this document, the PSD application, for the proposed project and evaluated herein, has been initially received on August 21, 2017. Subsequently, two letters containing revisions to the PSD modeling analysis have been received by the DAQ on October 26, 2017 and February 20, 2018.

As discussed in Section 4.0 above, emissions increases estimated from the project are above the significant Emission rates (SER), as defined under 40 CFR 51.166(b)(23), for nitrogen oxides (NO_X), particulate matter equal to or less than 10 micrometers diameter (PM_{10}), particulate matter equal to or less than 2.5 micrometers diameter ($PM_{2.5}$), volatile organic compounds (VOCs), and carbon monoxide (CO). Therefore, per 40 CFR 51.166(m)(1)(i)(a), an ambient air quality analysis of project emission impacts is performed for NO_X, PM_{10}, $PM_{2.5}$, ozone (VOCs), and CO. The analysis also includes modeling of project sulfur dioxide (SO_2) emissions. NO_X and VOC emission increases are evaluated in terms of contributions to ozone formation. SO_2 and NO_X emission increases are evaluated in terms of contributions to secondary $PM_{2.5}$ formation. Project impacts on Class I PSD Increments and Air Quality Related Values (AQRVs) are evaluated consistent with the conditions under 40 CFR 51.166(p). Project emissions of total suspended particulate (TSP) are shown to exceed the SER triggering review under the State Ambient Air Quality Standards (SAAQS) as defined by 15A NCAC 02D .0403, and therefore, a modeling demonstration for TSP is

[30] Circuit Court Decision on PM2.5 Significant Impact Levels and Significant Monitoring Concentration, Questions and Answers, US EPA, OAQPS, March 4, 2013.

conducted. Note that TSP emissions are assumed to be equal to PM_{10} emissions. Table 7-1 shows the project net emissions increases for all PSD pollutants evaluated under source impact analysis.

As part of the project, Duke-Lincoln proposed to construct **new fencing** that would expand the existing ambient boundary of the facility. The new fencing would provide additional ambient boundary around the new turbine test facility located approximately 500 meters (m) southeast of the existing facility.

Table 7-1: Project Emissions

Pollutant	Annual Emission Rate tons/yr	Significant Emission Rate tons/yr	PSD Review?
NO_x	717.1	40	Y
$PM_{2.5}$	52.2	10	Y
PM_{10}	52.2	15	Y
PM (TSP) Filterable Only	31.3	25	Y
SO_2	28.0	40	N****
CO	822.9	100	Y
VOC's **	119.6	40	Y
Lead	0.02	0.6	N
H2SO4 ***	5.59	7	N

*** VOC is an ozone precursor evaluated under ozone analysis.*
**** No SIL or NAAQS exist; modeled by NC Toxics standards*
***** Ambient analysis conducted even though project emissions were less than SER.*

Class II Area Significant Impact Air Quality Modeling Analysis

A significant impact analysis is conducted for the pollutants shown in Table 7-1 that require PSD analysis and that have established Class II Area Significant Impact Levels (SIL). The modeling results are compared to the applicable Class II Area SIL as defined in the NSR Workshop Manual, NC DAQ memoranda, and EPA guidance to determine if a full impact air quality analysis would be required for that pollutant.

Emissions are modeled assuming 8,760 hours per year facility operation and worst-case operating scenarios as determined by the turbine load screening modeling. The proposed new turbine operating scenarios included several turbine configuration versions and various load and startup/shutdown operations. The operating scenario source parameters and emission rates are provided by the turbine manufacturer, Siemens. Each operating scenario is modeled for natural gas and fuel oil combustion. Multiple factors including combustion fuel type, load, and turbine version are considered in the screening and identification of worst-case impact operating scenario that is selected for the SILs analysis. Results of the screening analysis showed that the worst-case impact operating scenario for all PSD pollutants and averaging periods would be turbine version C, combusting fuel oil during startup. Therefore, all SILs modeling for all PSD pollutants is conducted assuming emissions and stack release parameters from turbine version C combusting fuel oil during startup. Table 7-2 below shows the results of the screening analysis for each operating scenario evaluated. The maximum impact scenario is highlighted in red.

Table 7-2: New Turbine Operating Scenario Load Screening Results (ug/m^3)

Turbine Version	Fuel	Turbine Load	Maximum Modeled Concentration per Averaging Period (µg/m^3)									
			NOx 1-hour	NOx Annual	CO 1-hour	CO 8-hour	$PM_{2.5}$ 24-hour	$PM_{2.5}$ Annual	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	TSP Annual
Version A	Gas	BASE	22.38	0.21	3.03	1.09	0.09	0.006	0.09	0.006	0.09	0.006
		80%	19.88	0.18	2.69	0.96	0.08	0.005	0.08	0.005	0.08	0.005
		50%	10.34	0.09	2.52	0.88	0.08	0.005	0.08	0.005	0.08	0.005
		Startup	31.71	0.32	108.11	45.08	0.20	0.013	0.20	0.013	0.20	0.013
		Shutdown	9.94	0.10	85.08	35.48	0.16	0.010	0.16	0.010	0.16	0.010
	Oil	BASE	22.94	0.20	3.32	1.18	0.19	0.013	0.19	0.013	0.19	0.013
		80%	19.94	0.17	2.89	1.02	0.20	0.013	0.20	0.013	0.20	0.013
		70%	21.70	0.18	3.15	1.10	0.22	0.014	0.22	0.014	0.22	0.014
		Startup	61.89	0.62	332.15	139.03	0.39	0.025	0.39	0.025	0.39	0.025
		Shutdown	30.06	0.30	254.06	106.35	0.40	0.026	0.40	0.026	0.40	0.026
Version B	Gas	BASE	22.78	0.22	3.08	1.11	0.09	0.006	0.09	0.006	0.09	0.006
		80%	19.94	0.18	2.70	0.97	0.08	0.005	0.08	0.005	0.08	0.005
		50%	10.41	0.09	2.53	0.89	0.08	0.005	0.08	0.005	0.08	0.005
		Startup	32.55	0.33	109.98	45.87	0.20	0.013	0.20	0.013	0.20	0.013
		Shutdown	10.12	0.10	86.69	36.15	0.16	0.010	0.16	0.010	0.16	0.010
	Oil	BASE	23.07	0.21	3.34	1.19	0.19	0.012	0.19	0.012	0.19	0.012
		80%	20.08	0.17	2.91	1.03	0.20	0.013	0.20	0.013	0.20	0.013
		70%	21.87	0.18	3.17	1.11	0.22	0.014	0.22	0.014	0.22	0.014
		Startup	50.39	0.51	337.97	141.47	0.39	0.026	0.39	0.026	0.39	0.026
		Shutdown	30.72	0.31	259.02	108.42	0.40	0.026	0.40	0.026	0.40	0.026
Version C	Gas	BASE	27.01	0.24	3.65	1.17	0.08	0.006	0.08	0.006	0.08	0.006
		80%	20.58	0.19	2.78	0.93	0.07	0.005	0.07	0.005	0.07	0.005
		50%	10.25	0.09	2.50	0.90	0.07	0.005	0.07	0.005	0.07	0.005
		Startup	44.56	0.46	135.49	58.35	0.26	0.017	0.26	0.017	0.26	0.017
		Shutdown	13.08	0.14	108.81	46.86	0.19	0.012	0.19	0.012	0.19	0.012
	Oil	BASE	24.28	0.23	3.52	1.25	0.17	0.012	0.17	0.012	0.17	0.012
		80%	19.79	0.18	2.87	1.03	0.16	0.011	0.16	0.011	0.16	0.011
		70%	22.51	0.20	3.26	1.16	0.18	0.012	0.18	0.012	0.18	0.012
		Startup	65.80	0.68	408.08	174.90	0.48	0.031	0.48	0.031	0.48	0.031
		Shutdown	39.32	0.41	320.95	137.56	0.45	0.029	0.45	0.029	0.45	0.029

The worst-case impact operating scenario is selected as the basis for the Class II SILs analysis. Thus, all pollutants and averaging periods are modeled assuming source emissions and parameters from turbine version C and oil combustion during startup. Table 7-3 below shows the results of the Class II SILs analysis and that all pollutants with exception to 1-hour NO_2 are modeled below the Class II Area SILs. Therefore, project impacts are shown to not cause or contribute to a violation of the NAAQS or Class II PSD Increments for pollutants where modeled concentrations are less than the applicable SIL.

Project impacts for 1-hour NO_2 are modeled above the Class II Area SIL. Impacts above the 1-hour NO_2 SIL (7.5 µg/m^3) extend up to 50 km from the Lincoln Combustion Turbine Station. EPA defines 50 km as the maximum distance for applications of the AERMOD dispersion modeling system based on model performance evaluations and steady-state modeling assumptions. Therefore, only receptors up to 50 km away that are modeled above the 1-hour NO_2 SIL are evaluated in the full impact analysis. Note that both the annual and 1-hour NO_2 SILs analysis is relied on the EPA default Ambient Ratio Method 2 (ARM2) Tier 2 model option and the default NO_2/NO_X in-stack ratio (ISR) of 0.5.

Table 7-3: Class II Significant Impact Results (µg/m³)

Pollutant	Averaging Period	Project Maximum Impact	Class II Significant Impact Level	Class II Significant Impact Area (km)
CO	1-hour	408.08	2000	N/A
	8-hour	174.90	500	N/A
SO_2	1-hour	0.92	8	N/A
	3-hour	0.62	25	N/A
	24-hour	0.15	5	N/A
	Annual	0.015	1	N/A
NO_2	1-hour	**57.05**	**7.5**	**50***
	Annual	0.93	1	N/A
TSP	24-hour	0.48**	5	N/A
	Annual	0.05**	1	N/A
PM_{10}	24-hour	0.48	5	N/A
	Annual	0.05	1	N/A
$PM_{2.5}$	24-hour	0.33	1.2	N/A
	Annual	0.03	0.2	N/A

* Receptors modeled above the 1-hour NO_2 SIL define impacted areas evaluated in full impact modeling analysis.
** Based on total particulate matter emissions (PM or TSP) of 52.2 tons/yr. As per PSD regulation, only filterable portion (31.3 tons/yr) is regulated under PM. Thus, the modeling analysis is conservative.

Class II Area Full Impact Air Quality Modeling Analysis

A Class II Area NAAQS full impact analysis is conducted for 1-hour NO_2 based on project emissions impact receptor locations modeled above the 1-hour NO_2 SIL, development of a nearby source inventory, Tier 3 1-hour NO_2 modeling options and refinements, and representative background 1-hour NO_2 background concentrations.

The NAAQS analysis for 1-hour NO_2 included modeling of worst-case facility-wide potential emissions and a nearby source inventory as determined by the 20D screening approach. Project worst-case emissions are based on turbine version C and fuel oil combustion during startup conditions. The existing 16 simple cycle turbines at Duke-Lincoln are modeled assuming worst-case, permitted allowable NO_X emissions from fuel oil combustion (i.e., 287 lb/hr). With exception to Duke-Marshall and Duke-Allen facilities, all nearby sources are modeled with potential emissions as recorded in the most current NCDAQ emissions inventory database. All Duke-Marshall and Duke-Allen coal-fired boiler units are modeled using the 2-year (2015-2016) hourly average heat input values multiplied by the enforceable SIP (02D .0519) NO_X emission limits for coal-fired boilers (i.e., 1.8 lb NO_X/MMBtu). Lastly, nearby sources and emissions more than 15 km from the project are modeled as one representative stack.

The full impact analysis is spatially refined to include only sources and receptors located within a 50-km radius from the Duke-Lincoln project. This refinement is consistent with spatial application limitations of the AERMOD modeling system steady-state assumptions and 1-hour NO_2 transport assumptions. Some sources that would have been otherwise screened out of the inventory using 20D are included where isopleths equivalent to the 1-hour NO_2 SIL (7.5 µg/m³) encompassed these smaller, more distant sources. In other words, the significant impact area for 1-hour NO_2 is expanded to include all nearby sources and receptors where worst-case project impacts (i.e., turbine version C, oil combustion, startup conditions) are modeled above the SIL.

The Tier 3 modeling approach for 1-hour NO_2 followed all applicable EPA modeling guidelines. Duke-Lincoln selected the ozone limiting method (OLM) modeling option to refine 1-hour NO_2 cumulative impacts predicted with

AERMOD. OLM is a regulatory default Tier 3 modeling option under the EPA-preferred AERMOD modeling system. The OLM model option required development of an hourly ozone data file and NO_2/NO_X in-stack ratio (ISR) data inputs for all modeled sources. The ozone data covers the 5-year period of analysis 2012-2016 and derives hourly ozone values from the following representative datasets, in order of preference: Lincoln County Monitor (seasonal ozone data, April-October), NFS Candor Monitor (winter ozone data, November-March), and season-hourly varying ozone data developed from Lincoln and Candor data. The season-hourly varying data is based on the 2nd high hourly values taken from each hour-of-day in each seasonal subset across the 5-years of available ozone data. As such, the seasonal-hourly varying data includes 24 hourly values for each of the four seasons, or 96 ozone values in all. The seasonal-hourly varying data is used to fill in missing or negative ozone data values found in the raw hourly data from the Candor and Lincoln datasets. The ISR inputs for nearby sources 1-3 km from the project assumed 0.2 NO_2/NO_X, as per EPA Tier 3 guidance. An ISR of 0.1 NO_2/NO_X is applied to Duke-Lincoln, Duke-Allen, and Duke-Marshall sources based on available NO_2/NO_X stack-test data for electric generator sources combusting either coal, natural gas, or fuel oil. EPA Region 4 was consulted on the Tier 3 approach for the project via email correspondence from NC DAQ on February 8, 2018, as per Appendix W Section 4.2.3.4(e). Review comments from Region 4 on the Tier 3 approach did not alter the implementation of the selected modeling methodologies and options.

Temporally varying, representative background 1-hour NO_2 concentrations are developed from the Yorkville, Georgia monitoring station (Site ID: 37-119-0041) dataset covering the period 2013-2015. The Yorkville data is deemed representative of the project site based on similarities in rural setting and relative proximity to urban areas. The 3-year dataset is reduced to four seasonally-varying diurnal profiles based on seasonal 3rd high values taken from each season and hour-of-day subset. In some cases where seasonal data completeness approached 80%, 2nd and 1st high values are used. As such, four seasonal-hourly varying diurnal profiles are developed (e.g., 96 1-hour NO_2 background values) and paired with modeled 1-hour NO_2 concentrations to determine cumulative impacts across the 5-year modeling period.

Model impacts from facility-wide and nearby source emissions are summed with monitored background concentrations and then compared to the NAAQS to determine if there is a modeled violation of the NAAQS. Results of the 1-hour NO_2 full impact NAAQS analysis is presented in Table 7-4 below. As shown, the cumulative impacts from all sources and background 1-hour NO_2 concentrations show a modeled violation of the NAAQS. Therefore, a culpability analysis is conducted to demonstrate that the modeled impacts from the project and existing facility sources do not cause or significantly contribute (i.e., equal to or greater than the 1-hour NO_2 SIL) to any of the modeled violations.

Table 7-4: Class II NAAQS Full Impact Analysis Results (μg/m³)

Pollutant	Averaging Period	Model Design Value Criteria	Model Concentration	Monitor Background Concentration	Total Concentration	NAAQS
NO_2	1-hour	Maximum 8th highest Max Daily 1-hour Value Averaged Over 5 Years	211.7	17.2	**228.9**	**188**

The culpability analysis is based on modeled violations of the 1-hour NO_2 NAAQS at three coarse-gridded receptors from the original subset of receptors where the new turbine project emissions impacts are modeled above the SIL. Hotspot receptor grids are centered over the three receptor locations where modeled violations occurred to improve concentration gradient resolution. One grid is centered on the modeled violations approximately 24 km north of the Duke-Lincoln and another grid is located approximately 19 km northeast of Duke-Lincoln. Each hotspot grid used 100-meter spacing and covered a 2 km by 2 km square area. The results of the culpability analysis using the hotspot grids is shown in Table 7-5 below. As shown, there are no events (i.e., times and/or receptor locations) where modeled violations coincided with Duke-Lincoln project contributions greater than or equal to the 1-hour NO_2 SIL. Modeled violations are analyzed for project contributions out to the 300th ranked model design value to verify that project impact contributions are below the SIL, and therefore, not significant. In summary, based on the culpability modeling demonstration, the Duke-Lincoln new turbine project neither contributes nor causes a violation of the 1-hour NO_2 NAAQS.

Table 7-5: Culpability Analysis of 1-hour NO_2 NAAQS Demonstration ($\mu g/m^3$)

Hotspot Grid	Source Group	# Receptors > 188 $\mu g/m^3$ NAAQS	# Receptors >= 7.5 $\mu g/m^3$ SIL at Modeled Violation of 188 μg/m3 NAAQS	Modeled Ranks Over the NAAQS, and Analyzed for Project Contributions
24 km North, 2km x 2km 100-m Spacing	Duke-Lincoln PSD Project	0	0	None
	Nearby Sources	5701	5701	8^{th} – 260^{th}
	All Sources + Background	5701	5701	8^{th} – 267^{th}
19 km Northeast, 2km x 2km 100-m Spacing	Duke-Lincoln PSD Project	0	0	None
	Nearby Sources	2363	2363	8^{th} – 146^{th}
	All Sources + Background	2363	2363	8^{th} – 157^{th}

Class II Area Tier 1 Screening Analysis for $PM_{2.5}$ and Ozone Precursors

A Tier 1 screening analysis is conducted to evaluate project precursor emissions impacts on secondary formation of $PM_{2.5}$ in Class II areas. A Tier 2 cumulative analysis is conducted for ozone. Both the screening analysis for $PM_{2.5}$ and cumulative analysis for ozone is based on methodologies taken from EPA's draft *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (December 2, 2016). Additional methodologies for the ozone cumulative analysis are adapted from EPA's draft *Guidance on the Use of Models for Assessing the Impacts Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and $PM_{2.5}$* (January 2017).

MERPs are defined as the screening emission level (tpy) above which project precursor emissions would conservatively be expected to have a significant impact on secondary $PM_{2.5}$ or Ozone formation. A MERP value is developed for each precursor pollutant from photochemical modeling validated by EPA and a "critical air quality threshold". The MERPs guidance relies on EPA's 2016 draft SILs for $PM_{2.5}$ and ozone as the critical air quality threshold to develop conservative MERPs values. As such, NO_X and SO_2 project emissions are assessed by separately derived $PM_{2.5}$ MERPs values. $PM_{2.5}$ MERPs values selected for Duke-Lincoln are based on the most conservative values taken from Table 7.1 of the MERPs guidance that represent hypothetical sources located in the eastern U.S. The project impacts on secondary $PM_{2.5}$ are determined by summing the SO_2 project emissions as a percentage of the SO_2 MERP with the NO_X project emissions as a percentage of the NO_X MERP, and then adding the primary $PM_{2.5}$ emissions impacts predicted by dispersion modeling as a percentage of the SIL, and finally, comparing the total sum to a normalized total of 100% (see Scenario D in MERPs guidance). The 100% value represents a dimensionless, normalized threshold for evaluating the combined primary $PM_{2.5}$ and secondary $PM_{2.5}$ impacts from NO_X and SO_2 emissions on total $PM_{2.5}$ concentrations. Table 6 (of the guidance) shows the 24-hour and annual SO_2 and NO_X project emissions along with representative and conservative MERPs values for the eastern US. Table 7-6 below also shows primary $PM_{2.5}$ impacts as a percentage of the SILs. The combined percent total of primary and secondary $PM_{2.5}$ percentages are less than 100%, and therefore, indicates project impacts on $PM_{2.5}$ will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

Table 7-6: Tier 1 Screening of $PM_{2.5}$ Total Impacts

Secondary Pollutant	SO_2 Project Emissions (tpy)	SO_2 MERP (tpy)	NO_X Project Emissions (tpy)	NO_X MERP (tpy)	Secondary $PM_{2.5}$ Impact % NO_X MERP + % SO_2 MERP	Modeled Primary $PM_{2.5}$ Impact % of SIL	% Total Primary + Secondary $PM_{2.5}$
24-hour $PM_{2.5}$	28.0	628	717.1	2,295	35.7 %	25.8 %	61.5 %
Annual $PM_{2.5}$	28.0	4,013	717.1	10,144	7.8 %	1.5 %	9.3 %

The cumulative analysis for ozone relied on NO_X and VOC MERPs photochemical modeling ozone values taken from the hypothetical source located in Horry, South Carolina and an ambient 8-hour ozone monitoring design value taken from the Lincoln County Crouse Monitor (AQS Site ID: 37-109-0004). The selection of hypothetical source MERPs ozone values is based on similar NO_X and VOC emissions, geographic representativeness, and conservatism. The Crouse Monitor and 2014-2016 monitoring period data is determined as representative based on the relative proximity of the monitoring station to the project location (approximately 20 km west of Duke-Lincoln). Table 7-7 below shows the relevant MERPs emissions, ozone values, and project emissions used to determine the scaled project ozone impacts. The scaled project ozone impacts are added to the 8-hour ozone design value from the Crouse Monitor to demonstrate that cumulative impacts are below the 8-hour ozone NAAQS of 70 ppb.

Table 7-7: MERPs Screening of Ozone Precursors

Ozone Precursor Pollutant	MERPs Source: Horry, SC (tpy)	Project (tpy)	MERPs Source: Horry, SC 8-hour Ozone (ppb)	Scaled, Project 8-hour Ozone (ppb)	8-hour Ozone, 2014-2016 Design Value, Crouse Monitor (ppb)	Total Cumulative 8-hour Ozone (ppb)	8-hour Ozone NAAQS (ppb)
NO_X Precursor	1000	717.1	3.66	2.6	67	69.6	70
VOC Precursor	500	119.6	0.03	0.01			

Non-Regulated Pollutant (Total Suspended Particulates) Impact Analysis

Total suspended particulate (TSP) project emissions are estimated above the SER of 25 tpy as specified under 40 CFR 51.166(b)(23). While the TSP NAAQS is revised in 1987 to narrow focus and regulation of PM_{10}, North Carolina State Ambient Air Quality Standards (SAAQS) still requires evaluation of both PM_{10} and TSP separately in accordance with 15A NCAC 02D .0403. As such, Duke-Lincoln modeled facility-wide TSP project emissions using AERMOD and the same model setup as the PM_{10} SILs modeling analysis to show project impacts are below the 24-hour (5 µg/m^3) and annual (1 µg/m^3) TSP SILs, and thereby demonstrate compliance with the 24-hour (150 µg/m^3) and annual (75 µg/m^3) TSP SAAQS. Note that PM_{10} emissions are assumed to be equivalent to TSP emissions, and thus, are represented by the same modeling analysis files. Table 7-8 below shows the results of the modeling analysis and that the modified facility-wide emissions impacts will not cause or contribute to a violation of the TSP SAAQS.

Table 7-8: Class II TSP SAAQS Significant Impact Analysis Results (µg/m^3)

Pollutant	Averaging Period	Project Modeled Concentration	SAAQS SIL
TSP	24-hour	0.48	5
	Annual	0.05	1

8.0 Additional Impact Analysis

Additional impact analyses are conducted for growth, soils and vegetation, visibility impairment, and ozone.

Growth Impact

No secondary growth is proposed for the project based on the expectation that no additional employees will be required for the proposed project.

Soils and Vegetation

The project impacts on soils and vegetation is analyzed by comparing the maximum modeled concentrations to screening thresholds recommended in EPA's "A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA-450/2-81-078). The modeled concentrations are well below the screening thresholds. Therefore, little or no significant impacts are anticipated from the project to soils and/or vegetation. See PSD application Table 6-21 in the modeling report section for further details of the modeled project impacts compared to secondary NAAQS and screening thresholds. Modeled concentrations are taken from the SILs analysis for each applicable pollutant.

Class II Visibility Impairment Analysis

The Class II visibility analysis is conducted for Lake Norman State Park based on significant project emissions of visibility-impairing pollutants such as NO_X, SO_2, $PM_{2.5}$, and PM_{10}. Lake Norman State Park is located 24 km northeast of the Duke-Lincoln facility. Plume perceptibility and contrast impact criteria are analyzed according to the US EPA's Workbook for Plume Visual Impacts Screening and Analysis (Revised, October 1992). Analysis procedures relied on US EPA's VISCREEN model to determine if project impacts are below plume perceptibility and contrast criteria. See PSD application section 6.11.4 for further details of the analysis. The conclusion of the analysis is that the Duke-Lincoln project impacts are below applicable visibility criteria.

Ozone Impact

The project NO_X and VOC emissions exceed the ozone SER of 40 tons per year for NO_X and VOCs as specified in 40 CFR Part 51.166(b)(23)(i). Therefore, project NO_X and VOC emissions impacts on ambient ozone levels are analyzed using a Tier 1 cumulative analysis approach. The cumulative analysis relied on ambient ozone data and MERPs hypothetical source impacts. Please see details of the analysis discussed previously in this review report. All indications are that project emissions impacts would not cause or contribute to an exceedance of the 8-hour ozone NAAQS.

9.0 Class I Increment/Air Quality Related Values (AQRV) Regional Haze Impact and Deposition Analyses

Class I Area Significant Impact Air Quality Modeling Analysis

The CALPUFF modeling system (version 5.8.5) using the VISTAS CALMET dataset is applied to the project emissions impacts analyzed and screened for comparison to the Class I Area SILs. Please see PSD application for further details on specific model procedures. The following Class I areas are included in the Class I SILs analysis: Cape Romain Wilderness, Great Smokey Mountains NP, James River Face Wilderness, Joyce Kilmer-Slickrock Wilderness, Linville Gorge Wilderness, Shining Rock Wilderness. Emissions analyzed from the project included operating scenarios for Turbine Version C, natural gas and oil combustion, and testing and continuous operating modes. A summary of maximum project impacts modeled for the Linville Gorge Wilderness compared to Class I SILs for NO_2, PM_{10}, and $PM_{2.5}$ are shown in Table 9-1 below. As shown, modeled project impacts are well below Class I SILs, and therefore, would not cause or contribute to a violation of the Class I PSD Increments established for NO_2, PM_{10}, and $PM_{2.5}$.

Table 9-1: Class I Significant Impact Results for Linville Gorge Wilderness (µg/m^3)

Pollutant	Averaging Period	Project Maximum Impact	Class I Significant Impact Level
NO_2	Annual	0.009	0.1
PM_{10}	24-hour	0.029	0.32
	Annual	0.0009	0.20
$PM_{2.5}$	24-hour	0.029	0.27
	Annual	0.0009	0.05

Class I Air Quality Related Values (AQRV) Regional Haze Impact and Deposition Analyses

The project includes significant emissions of pollutants with established Class I Area Air Quality Related Values (AQRVs). AQRVs have been developed for both visibility and atmospheric deposition according to various Federal Land Manager (FLM) guidelines. The project included significant emissions of visibility-impairing pollutants such as NO_X, SO_2, $PM_{2.5}$, and PM_{10} as well as significant emissions affecting nitrogen species deposition.

Federal Land Managers (FLMs) are notified of the PSD project following email transmittal of the Class I Modeling protocol May 19, 2017. Based on the project emissions and relative close proximity to Class I Areas, the US Forest Service requested an AQRV analysis via email on June 1, 2017.

Project impacts to AQRVs are modeled using the same CALPUFF modeling system and emissions assumptions employed for the Class I SILs analysis. Model particulars are developed using the FLM FLAG 2010 guidance document. Further details of the analysis can be found in the application model report. All visibility impacts are modeled below the 5% delta-deciview criteria used to measure changes in visibility at Class I areas. See application Table 6-19 for delta-deciview impacts at each Class I area. Nitrogen deposition project impacts are modeled below the screening threshold of 0.01 kg/ha/yr at all analyzed Class I areas. Therefore, the AQRV analysis demonstrates that project impacts are below all applicable AQRV thresholds.

10.0 Facility Wide Air Toxics

Refer to Section 4.0 above.

11.0 Facility Emissions Review

The first page of this application review includes facility-wide actual emissions, as reported to DAQ for calendar year 2012-2016.

12.0 Public Notice/EPA and Affected State(s) Review

This permit application's processing is conforming with the public participation requirements, pursuant to both 15A NCAC 0530 "Prevention of Significant Deterioration" and 15A NCAC 02Q .0300 "construction and operation permits".

A public notice (See Appendix B) for the availability of preliminary determination and the draft Title V will be published in a local newspaper of general circulation for 30 days for review and comments. A copy of the public notice will be provided to the EPA, and all local and state authorities having authority over the location at which the proposed modification is to be constructed. Draft permit documents will also be provided to EPA, affected states, and all interested persons in mailing list, maintained by the DAQ. Finally, all documents will be placed on the DEQ's website and a complete administrative record for the draft permit documents will be kept for public review at the DEQ's Mooresville Regional Office for the entire public notice period (30 days).

As this application is not processed pursuant to 15A NCAC 02Q .0500 "Title V procedures", none of the public participation requirements contained therein apply to the application.

Appendix C includes listing of both the entities and the documents to be sent to each listed entity for the proposed PSD major modification, satisfying the requirements in §51.166(q) "public participation".

13.0 Stipulation Review

The following changes were made to the Duke Energy Carolinas, LLC, Lincoln Combustion Turbine Station, Air Quality Permit No. 07171T10:

Old Page No. [Air Permit No. 07171T10]	**New Page No.** [Air Permit No. 07171T11]	**Condition No.**	**Changes**
3	3	Section 1 Table	Include new sources and control devices: simple cycle combustion turbine (ID No. ES-19), diluent selective catalytic reduction system (ID No. CD-19a), oxidation catalyst (ID No. CD-19b), and No. 2 fuel oil storage tank (ID No. ES-20). Include a footnote for the above changes, accomplished per 02Q .0501(c)(2).
-	14 through 21	Section 2.1 C.	Include this Section for regulatory requirements for the new combustion turbine (ID No. ES-19).
-	22	Section 2.1 D.	Include this Section for regulatory requirements for the new No. 2 fuel oil fixed-roof storage tank (ID No. ES-20).
-	23 through 30	Section 2.2 A.	Include this Section for multiple sources' regulatory requirements for the combustion turbine (ID No. ES-19) and the No. 2 fuel oil storage tank (ID No. ES-20).
15 through 25	32 through 41	Section 3	Include the most current version of the General Conditions.

14.0 Conclusions, Comments, and Recommendations

- The regulation in 02Q .0112 "Applications Requiring Professional Engineer Seal" includes that a professional engineer registered in North Carolina shall be required to seal technical portions of air permit applications for new sources and modifications of existing sources that involve: design, determination of applicability and appropriateness, or determination and interpretation of performance; of air pollution capture and control systems.

  The application includes a diluent SCR and an optional CO oxidation catalyst. However, none of these control devices are yet designed. The applicant has stated that the technical data will be provided to DAQ once these emission control devices are designed. The DAQ will include a specific requirement in the permit for submittal of technical data on the control devices upon completion of their design. At that time, DAQ will perform the evaluation of each control device.

- Lincoln County Planning and Inspection Department has provided a zoning consistency determination in accordance with 02Q .0304(b)(1) on August 17, 2017, stating that the zoning administrator has received a copy of the air permit application and the proposed operation is consistent with applicable zoning ordinances.

- The draft permit (pre-public notice version) was emailed to the Mooresville Regional Office (MRO) for review on May 17, 2018. MRO did not email with any comment or changes to the draft permit documents.

- The draft permit (pre-public notice version) was sent to the Permittee for review on May 17, 2018. Duke Energy emailed on May 30th with comments on both the draft preliminary determination and the permit. All DEC comments on the draft permit are discussed below, in addition to any comments on the draft preliminary determination (if the comment on the preliminary determination is different than any comments on the draft permit). The DAQ also discussed with DEC the comments via telephone on June 18, 2018[31]:

DEC Comment 1:

Throughout the permit, state that the heat input rates (million Btu/hr) are "maximum nominal" values instead of "maximum" for each fuel firing for each Version.

DAQ Response:

Agreed. This change will be made both in the draft preliminary determination and the air permit.

DEC Comment 2:

For footnote to Section 1 Table in the draft permit, the requirement for submittal of a second application under the two-step process for the proposed Siemens turbine project needs to be clarified to state that the second application is due on or before 12 months after commencing operation of new turbine under Duke Energy's control.

DAQ Response:

Disagreed.

The clock for submitting a second application for the proposed project under 02Q .0501(c)(2) begins with the commencement of operation in configuration Version A, as correctly included in Section 2.2 A. 2. a. NC's Title V program in 02Q .0500 does not differentiate the title V application submittal requirement for any emissions unit based on its developmental phase or commercial operation.

Finally, it needs to be emphasized that the question on owner/operator for the new CT was resolved and adequately discussed in Section 3.1 above. In brief, the applicant (DEC) confirmed to the DAQ that it would be the owner/operator for the new CT as soon as the air quality permit was issued by DAQ and it would assume all compliance obligations, air pollution control responsibilities, and all other requirements under CAA and the NC's SIP-approved regulation for all configurations, starting with the configuration Version A.

In summary, the footnote to the Section 1 Table will be clarified to state that the submittal deadline for the second application under 02Q .0501(c)(2) would be 12 months from the commencement of operation in Version A.

DAQ Comment 3:

In Section 2.1 C. Table and Section 2.2 A.1. b. Table, clarify the meaning of commercial operation with respect to the proposed project.

DAQ Response:

The DAQ has decided to describe the commercial operation of the CT as "post-developmental operation" to remove any confusion.

DEC Comment 4:

In Section 2.1 C.1. c., remove a Method 9 testing requirement at an interval of 1100 hours for fuel oil firing scenario.

---

[31] Rahul Thaker (DAQ) with Ann Quillian (DEC).

DAQ Response:

Agreed. Ultra-low diesel fuel is a clean fuel (15 ppm sulfur content). Visible emissions are non-existent to negligible. Thus, the draft permit Section 2.1 C. 1. c. will be revised to state no monitoring or recordkeeping can be required.

DEC Comment 5:

In Section 2.1 C. 2.i., clarify the initial start-up of the affected facility in the context of NSPS.

DAQ Response:

This condition will be modified to state that the notification for initial start-up under NSPS (KKKK) is due within 15 days of initial start-up of the CT in Version A.

DEC Comment 6:

In Section 2.1 C. 4.c., clarify the initial start-up of the affected facility in the context of NESHAP.

DAQ Response:

This condition will be modified to state that the notification for start-up under NESHAP (YYYY) is due within 120 days of initial start-up of the CT in Version A.

DEC Comment 7:

In Section 2.1 C.6. a., clarify the acid rain application submittal requirement.

DAQ Response:

This condition will be modified to state that the acid rain application is required to be submitted to DAQ at least 24 months prior to commencement of operation in Version A.

DEC Comment 8:

The applicant contends that the BACT limits in Section 2.2 A.1. b. Table for various pollutants (CO, VOC, NOx, PM, PM10, PM2.5, and GHG) be revised to exclude periods of startup and shutdown, as with some Duke Energy-owned, NC-based other facilities' air quality permits. The Permittee argues that, for example, it takes time for control devices and the emissions unit to get to the proper operating conditions.

DAQ Response:

It needs to be emphasized that the DAQ had asked the DEC during the application review on whether it had proposed separate BACT for the CT during SU and SD periods. Through a response letter dated 9/21/17, DEC had stated the following:

> "The proposed combustion turbine is a simple cycle unit, and the duration of its startup and shutdown periods will be short. Separate BACT levels were not proposed for periods of unit startup and shutdown because the averaging times proposed for each pollutant (30 days for CO, 24 hours for VOC, 4 hours for NOx) are sufficient to include the startup and shutdown periods along with normal operating periods."

Due to the above statements from DEC, the DAQ proposed the same BACT for all periods of operation (normal, startup, shutdown, and malfunction).

In summary, no changes to the BACT, as drafted, will be made for startup and shutdown periods.

DEC Comment 9:

Modify the averaging period for NOx BACT from 4-hour rolling to 24-hour rolling.

DAQ Response:

In the submitted application, the applicant has proposed a BACT for NOx for both natural gas and fuel firing modes, with an averaging period of 4-hours rolling. Further, the applicant has proposed a NOx CEMS for compliance. Finally, the unit will be subject to NSPS Subpart KKKK for NOx when it commences commercial operation (post developmental operation) after it is turned over to DEC. The NSPS requires 4-hour rolling average for compliance with the NSPS NOx emission standard for simple cycle units, if a CEMS is used. Based on the above, it is reasonable for the DAQ to establish a NOx BACT on a 4-hour rolling average basis. In summary, no change to the NOx BACT averaging period will be made.

DEC Comment 10:

The applicant requests that the VOC BACT of 1.4 tons per consecutive 12-month period be changed to 1.5 tons per consecutive 12-month period for the new fuel oil storage tank.

DAQ Response:

The DAQ proposed the above 1.4 tons per consecutive 12-month limit for VOC based on the submitted application. The DAQ has reviewed again the VOC emissions estimate for the tank and found to be accurate. No change to the proposed BACT can be made for the above storage tank.

DEC Comment 11:

For Section 2.2 A.1. c. Table, DEC questions the inclusion of NOx limit of 679 to comply with the 1-hour NO_2 NAAQS if there are no PSD increments for the same pollutant for 1-hour averaging period. DEC further adds that if DAQ decides to include a NOx limit in the permit, it should include the largest emission rate modeled which is 858 lbs/hr.

DAQ Response:

At the outset, it needs to be noted that the emission rate included in the draft permit (679 lb/hr) corresponds to a successful demonstration for complying with the 1-hour NO_2 NAAQS. Currently, there are no PSD increments promulgated for this pollutant for 1-hour basis. The above emission rate for Version C configuration, when firing fuel oil during startup, exhibited the maximum impact (worst-case) from all possible combinations (version, load, fuel). Therefore, this emission rate corresponding to the worst-case impact was included in the draft permit. After further consideration, DAQ has decided to include the following emissions rates in the air permit corresponding to each fuel firing, based on different load conditions, and startup and shutdown periods. DAQ believes that by including all demonstrated emission rates for various scenarios, the permit will accurately describe the conditions under which the NAAQS demonstration for 1-hour NO_2 was conducted and approved.

Pollutant	Fuel	Emission Limit (lb/hr)					
		1-hr average					Annual average
		Base Load	80% Load	70% Load	Startup	Shutdown	
NO_2	Natural gas	857.8	635.3	251.4	458.8	134.7	N/A
	Fuel oil	719.4	524.97	513.1	679.4	406.0	

DEC Comment 12:

The Permittee has requested to delete the following conditions in Sections 2.2 A.1. d., f. and g.:

Section 2.2 A.1. d.

"The Permittee shall limit the operations of combustion turbine (ID No. ES-19) during startup and shutdown for all developmental phases (commissioning, testing, and validation) of each configuration (Versions A, B, and C) and commercial operation as below:
i. combined total 262 hours per consecutive 12-month period, natural gas firing
ii. combined total 40 hours per consecutive 12-month period, No. 2 fuel oil firing"

Section 2.2 A. 1. f.

"The Permittee shall limit the operation of combustion turbine (ID No. ES-19) to no more than 4,677 hours per consecutive 12-months period, when firing natural gas and No. 2 fuel oil, for each configuration (Versions A, B, and C), during normal operations, startups, shutdowns, malfunctions, commissioning, testing, and validation."

Section 2.2 A.1. g.

"The Permittee shall limit the operation of combustion turbine (ID No. ES-19) to no more than 4,677 hours per consecutive 12-months period, when firing natural gas and No. 2 fuel oil, for commercial operation, during normal operations, startups, shutdowns, and malfunctions."

For limits on SU (262 hours for consecutive 12-month period) and SD (40 hours for consecutive 12-month period), the Permittee argues that "this is [a] new technology and the DSCR will require some time to get the proper temperature, [hence,] Duke Energy is requesting that this requirement be removed. Otherwise as indicated in the next comment, Duke Energy would be happy to discuss further."

With respect to limitation on operating hours (4,677 hours for consecutive 12-month period) for each of the versions for all types of operation (normal, SU, SD, and malfunctions), the applicant argues that "Duke Energy did not request an operating limitation on this unit. Duke Energy would be interested in discussing with DAQ regarding this issue."

DAQ Response:

The project emissions (Version C for worst-case) for various pollutants reviewed for PSD applicability are based on only 4,677 hours for consecutive 12-months period (and not 8760 hours of operation), which incorporates limited numbers of hours for both startups (262 hours for any consecutive 12-months period) and shutdowns (40 hours for any consecutive 12-months period). With the underlying limitation on hours of operation (4677) for the proposed turbine, the draft air permit includes the accurate limitation on amount of emissions permitted and makes the term practically enforceable. In brief, the DAQ will remove the limitations on SU and SD operating hours as the total hours of operation (4677 hours) accounts for the limits on SU (262 hours) and SD (40 hours). Finally, DAQ cannot remove the limitation on total hours of operation (4677 hours), as the PSD applicability and compliance with the NAAQS are based on a limited 4677 hours of operation, and not 8760 hours of operation.

DEC Comment 13:

Section 2.1 A.1 i. includes stack testing requirements for CO, VOC, NOx, PM, PM10, PM2.5, and GHG, for the proposed CT for each configuration version and fuel, and for commercial operation.

The applicant requests removal of stack testing for CO, NOx, PM, PM10, PM2.5., and GHG, leaving only VOC stack testing. The applicant also requested to remove the requirement to test for each fuel type and each version of the configuration.

Specifically, for NOx, CO, and GHG, the applicant argues that stack testing is required for Version A only. For other versions (B and C) and commercial operation, the applicant contends that Part 75 certified CEMS and flow meters will sufficient to verify compliance.

For PM including PM10 and PM2.5, the applicant requests removal of all stack testing requirements, arguing that burning clean fuels (natural gas, ULSD) in CTs had not been typically been required any stack testing.

For VOC, the applicant requests only one-time testing for configuration Version C or after the unit is turned over to Duke Energy, although the applicant rescinded this request later[32].

DAQ Response:

The DAQ has determined that stack testing for NOx, CO, and GHG, is required for Version A and commercial operation (post developmental operation). In addition, continuous compliance with the BACT will be required through the certified CEMS.

For PM, PM10, and PM2.5., the DAQ has determined that some stack testing is required as the proposed CT is an unproven technology. DAQ will require stack testing for each of these pollutants for Version A and commercial operation (post-developmental operation). With respect to continuous compliance, no monitoring will be required for any PM indicators as per the draft permit.

For VOC, the DAQ has determined to require stack testing for Version A and commercial operation (post-developmental operation) only. With respect to continuous compliance, during the stack testing for VOC, if the Permittee determines that an oxidation catalyst will be needed to demonstrate compliance with the VOC BACT (in addition to CO BACT), the Permittee will be required to monitor inlet temperature to the catalyst.
DEC Comment 14:

In section 2.2 A.1. n. iii., the applicant requests that the following language be added instead of mandating to operate the DSCR at ammonia injection rate corresponding to 100 percent of injection rate observed during the stack testing during NOx CEMS downtimes or malfunctions:

> "In the case of a missing hour in conjunction with a Calibration Error Test or a Quarterly Linearity Test, the ammonia injection rate for the hour following the referenced test shall be adjusted to the injection rate determined during the performance test until a valid data status has been achieved."

The applicant later[33] added that the above permit language was similar to the recent Buck Steam Station permit (03786T35) and it provided a copy of the same.

DAQ Response:

The DEC proposed to use the ammonia injection rate, observed in demonstrating compliance with the NOx BACT, especially in conjunction with a Calibration Error Test or a Quarterly Linearity Test (i.e., when the NOx CEMs in not available for measurement of emissions), until its valid data status has been established. The DAQ finds this proposed permit language acceptable and reasonable, and believes that it ensures compliance.

DEC Comment 15:

In Section 2.2 A. 2.a., the applicant requests to clarify that the second application under 02Q .0504 shall be required within 1 year from the date the custody of CT is turned over to Duke Energy.

DAQ Response:

Disagreed. Please refer to the response to comment 2 above. No change to the permit condition will be made.

[32] Telephone communication between Rahul Thaker, NCDAQ, and Ann Quillian, Duke Energy, June 5, 2018.
[33] Ibid at footnote 31.

DEC Comment 16:

In Section 2.2 A. 2.b., the applicant requests a confirmation that notification to DAQ is required only one time for control devices (DSCR and oxidation catalyst).

DAQ Response;

Agreed. No change to the permit conditions will be made.

DEC Comment 17:

In Section 2.2 B.1., delete the air toxics limits for benzene emissions from two, existing fuel oil storage tanks (ID Nos. ES-17 and ES-18) and one new, No. 2 fuel oil storage tank (ID No. ES-20), as the storage tanks used to store only fuel oils are exempt from air toxics permitting pursuant to 02Q .0702(a)(19)(B).

DAQ Response:

Agreed. This is a mistake and it will be corrected.

In addition, Section 2. B. 2. will be deleted, as the procedural requirement in 02Q .0711 for emissions of toluene and xylenes does not apply. All emissions of these pollutants are from the exempt sources (NESHAP-subject seventeen combustion turbines and one fire pump engine, and three fuel oil storage tanks).

DEC Comment 18:

In Section 2.2 A. 1. B. Table, the applicant requests that the BACT be included in the form of lb/hr instead of lb/million Btu, as variations of heat input (Btu) and emission rate of PM (lb) do not change at the same rate.

DAQ Response:

Agreed. The BACT for these pollutants will be established in the unit of lb/hr.

DEC Comment 19:

In application review page 8, Section 3.3 "Project Emissions", make a correction to the exhaust flow rate for the gas turbine of 5,550 actual ft^3/min to 5.55 million actual ft^3/min.

DAQ Response:

Agreed.

DEC Comment 20:

In application review page 11, clarify that the NOx stack testing does not begin until the CT ceases to be a research and development unit per NSPS Subpart KKKK.

In addition, include a clarification that annual stack testing requirements do not apply as the applicant will be using the CEMS to meet and continue compliance with the NOx standards.

DAQ Response:

Agreed. The above clarifications on stack testing to begin after the unit is no longer a R&D unit and non-applicability of annual stack testing due to the use of CEMS, will be made.

- This engineer recommends issuing the revised permit after the completion of public comment period.

Appendix A [to Application Review for Application 5500082.17A]
RBLC Data

[only included in hard copy]

Appendix B [to Application Review for Application 5500082.17A]
Public Notice

[only included in hard copy]

Appendix C [to Application Review for Application 5500082.17A]
Listing of Entities and Documents to be Sent
[only included in hard copy]

Attachment 2 to Application Review of Applications 5500082.20A, .20B, and .21A
Duke Energy Corporation LCTS
Rationale for removal of NOx ozone season trading program requirement under CSAPR (40 CFR Part 97, Subpart BBBBB)

Background

The EPA established the original Cross-State Air Pollution Rule (CSAPR or "Transport Rule")[1] to address the interstate transport of emissions with respect to the 1997 ozone National Ambient Air Quality Standards (NAAQS) and the 1997 and 2006 fine particulate matter (PM2.5) NAAQS. This CSAPR was a federal implementation plan (FIP), requiring the upwind states to eliminate their "significant" contributions to the downwind states' non-attainment of these pollutants. With regard to the NOx ozone season trading program under this rule, EPA required NOx reductions in two phases (Phase 1 and Phase 2) for the affected states including NC.

Then the EPA finalized the CSAPR Update (CSAPR Update)[2] to address the interstate transport of emissions with respect to the 2008 ozone NAAQS. Through this rulemaking, EPA determined that NC did not contribute significantly to nonattainment in or interference with maintenance for the 2008 ozone standard for any downwind states[3]. Thus, EPA did not finalize the FIP for NC for this NAAQS, because the EPA's analysis supporting the final rule did not indicate that NC was linked to any identified downwind nonattainment or maintenance receptors with respect to the 2008 ozone standard[4].

In addition, because the 2008 ozone NAAQS is more stringent than the 1997 ozone NAAQS, EPA concluded that North Carolina was not linked to any remaining air quality concerns with respect to the 1997 ozone standard for which the state was regulated in the original CSAPR as above[5].

Addressing the D. C. Circuit Court[6] remand with respect to NC's Phase 2 NOx budget under the 1997 ozone standard, EPA concluded that the emissions from the state did not significantly contribute to nonattainment or interfere with maintenance of either the 1997 ozone NAAQS or 2008 ozone NAAQS in other states, and removed the state from the CSAPR ozone season trading program beginning in 2017 when the Phase 2 ozone season emission budget was scheduled to be implemented[7]. Accordingly, starting with the 2017 ozone season, NC was no longer subject to the CSAPR NOx ozone season trading program requirements (40 CFR 97 Subpart BBBBB) and electric generating units (EGUs) in the state were not allocated further allowances by EPA nor obligated to demonstrate compliance with CSAPR NOx ozone season requirements[8][9].

Finally, it needs to be noted that even for the more stringent 2015 ozone NAAQS, EPA proposed[10] to approve NC's State Implementation Plan (SIP), concluding that North Carolina sources would not significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. EPA supplemented[11] this approval with the updated modeling analysis based on the most

---

[1] 76 FR 48208 (August 8, 2011).
[2] 81 FR 74504 (October 26, 2016).
[3] 81 FR 74506, 74507.
[4] Id., 81 FR 74524.
[5] Id.
[6] *EME Homer City Generation, L.P., v. EPA*, No. 795 F.3d 118, 129–30, 138, July 28, 2015.
[7] Id.
[8] 81 FR 74555.
[9] States that are Affected by the Cross-State Air Pollution Rule (CSAPR) | US EPA and 40 CFR 97.510(a)(16).
[10] 84 FR 71854 (December 30, 2019).
[11] 86 FR 37942 (July 19, 2021).

current and technically accurate information, supporting its finding that NC's implementation plan contained adequate measures to prohibit emissions that would significantly contribute or interfere with the maintenance of the 2015 ozone standard in any other states.

DAQ Title V Permitting

DAQ included the original CSAPR requirements in Title V permits for all affected units in NC, including the combustion turbines (ID Nos. ES1 through ES4) at Cleveland County Generating Facility, after the US Supreme Court[12] upheld the CSAPR. Specifically, DAQ included in the permits the CSAPR trading programs requirements for annual NOx (40 CFR 97 Subpart AAAAA), ozone season NOx (Subpart BBBBB), and annual SO_2 (Subpart CCCCC).

Conclusion

With EPA's removal of NC ozone season NOx reductions requirements for 1997 ozone NAAQS and EPA's determination that NC is not subject to ozone season NOx reductions requirements for 2008 ozone NAAQS, the DAQ will revise the Title V permits for all affected units in NC under the origin

[12] *EPA v. EME Homer City Generation, L. P.*, No. 12-1182, Decided April 29, 2014.