NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: TBD

Region: Mooresville Regional Office
County: Cleveland
NC Facility ID: 2300372
Inspector's Name: Denise Hayes
Date of Last Inspection: 06/15/2021
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Cleveland County Generating Facility

Facility Address:
Cleveland County Generating Facility
240 Battleground Road
Kings Mountain, NC 28086

SIC: 4911 / Electric Services
NAICS: 221119 / Other Electric Power Generation

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

Permit Applicability (this application only)

SIP: 02Q .0504
NSPS: n/a
NESHAP: n/a
PSD: n/a
PSD Avoidance: n/a
NC Toxics: n/a
112(r): n/a
Other: n/a

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Chris Pierce O&M Manager (704) 471-9502 240 Battleground Road Kings Mountain, NC 28086	Jesse English Plant Manager (704) 278-6601 5755 NC 801 Highway Salisbury, NC 28147	Scott McMillan Project Manager (205) 992-0057 3535 Colonnade Parkway Birmingham, AL 35243

Application Data

Application Number: 2300372.21A & .22A
Date Received: 5/5/2021 (.21A), 2/7/2022 (.22A)
Application Type: Modification
Application Schedule: TV-Sign-501(b)(2) Part II

Existing Permit Data

Existing Permit Number: 09881/T09
Existing Permit Issue Date: 09/28/2020
Existing Permit Expiration Date: 06/30/2023

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2020	1.80	90.50	4.18	27.19	25.23	3.10	2.13 [Formaldehyde]
2019	3.10	151.93	6.74	45.62	42.23	5.19	3.57 [Formaldehyde]
2018	2.45	135.11	7.10	38.60	40.50	4.59	2.76 [Formaldehyde]
2017	2.69	137.66	6.20	40.80	39.78	4.68	3.14 [Formaldehyde]
2016	2.43	129.82	5.80	37.53	36.19	4.36	2.91 [Formaldehyde]

Review Engineer: Russell Braswell

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

Comments / Recommendations:
Issue 09881/T10
Permit Issue Date: TBD
Permit Expiration Date: June 30, 2023

1. Purpose of Applications:

Cleveland County Generating Facility (CCGF; the facility) operates a power plant in Cleveland County under Title V permit 09881T09. CCGF has submitted two applications to modify the existing permit.

a. Application 2300372.21A

The existing permit includes specific condition 2.2 B.3.a, which requires the facility to submit a permit application within 12 months of recommencing operation of the turbines ES2 and ES3. This condition was included in the permit because CCGF modified those turbines using a 2-step significant modification as allowed by 15A NCAC 02Q .0501(b)(2). CCGF submitted this application to comply with that specific condition.

That condition was added to the permit in response to applications 2300372.19B and .19C. In response to those applications, DAQ issued the T08 revision of the Title V permit.

In this application, CCGF did not request any changes to the permit with regards to the modifications originally requested in applications .19B and .19C. However, this application requests the removal of references to 40 CFR Part 97, Subpart BBBBB throughout the permit; this change is unrelated to the modifications of turbines ES2, ES3, and ES4.

b. Application 2300372.22A

The existing permit includes specific condition 2.2 C.3.a, which requires the facility to submit a permit application within 12 months of recommencing operation of the turbines ES1 and ES4. This condition was included in the permit because CCGF modified those turbines using a 2-step significant modification as allowed by 15A NCAC 02Q .0501(b)(2). CCGF submitted this application to comply with that specific condition.

That condition was added to the permit in response to applications 2300372.20A and .20B. In response to those applications, DAQ issued the T09 revision of the Title V permit (the existing permit).

In this application, CCGF did not request any changes to the permit with regards to the modifications originally requested in applications .20A and .20B. However, this application, similar to the .21A application, requests the removal of references to 40 CFR part 97, Subpart BBBBB throughout the permit.

2. Facility Description:

This facility is a power plant that produces electricity for sale to the power grid. The facility operates four simple-cycle combustion turbines. According to the most recent inspection report, the turbines are operated on a "demand-based schedule." In addition to the turbines, the facility also includes supporting activities, such as storage tanks.

3. Application Chronology:

- May 5, 2021, 2021 — Application .21A received. Assigned to Connie Horne[1].
- November 22, 2021 — An initial draft of the Title V permit and associated application review were sent to RCO staff.

[1] Senior Environmental Specialist, DAQ.

- December 2, 2021 — A draft of the Title V permit and associated application review were sent to SSCB, MRO, and CCGF.
- December 16, 2021 — Application transferred to Russell Braswell as result of comments received on the December 2 draft.
- January 24, 2022 — Email sent to CCGF regarding 1) formally labeling water injection as a control device in Section 1 of the permit, 2) the footnotes in Table 2.2 A.3 in the existing permit and the use of CEMS, and 3) data substitution for 02D .1418.
- February 3, 2022 — CCGF responded to the January 24 email.
- February 7, 2022 — Application .22A received.
- February 23, 2022 — A draft of the Title V permit and application review (updated based on comments received on the previous drafts and receipt of application .22A) were sent to RCO staff.
- XXXXX — A draft of the Title V permit and application review were sent to SSCB, MRO, and CCGF
- XXXXX — The Public Notice and EPA review periods began.
- XXXXX — The Public Notice period ended.
- XXXXX — The EPA Review period ended.
- XXXXX — Permit issued.

4. Changes to the Existing Permit:

a. 2-step significant modification under 15A NCAC 02Q .0501(b)(2) and 02Q .0504

When applying for a significant modification to a Title V permit, a facility may use the 2-step option covered by 15A NCAC 02Q .0501(b)(2) as long as the modification does not contravene an existing standard in the permit. Facilities that choose to use this option must submit an additional application within 12 months of commencing operation of the modified facility. When submitting applications .19B, .19C, .20A, and .20B, CCGF used the 2-step significant modification option.

Applications .19B and .19C were received at approximately the same time, so DAQ consolidated these two applications for processing. In response to applications .19B and .19C, DAQ issued the T08 permit revision.

Applications .20A and .20B were also received at approximately the same time, so DAQ consolidated these two applications for processing. In response to applications .20A and .20B, DAQ issued the T09 permit revision.

With the current application, CCGF has not requested any changes related to the T08 or T09 permit revisions. The conclusions reached by DAQ's review of those applications has not changed.

For ease of review, DAQ's review of the T08 and T09 permit revisions are included in this document as Attachment 1 and Attachment 2, respectively.

The requirement to submit a new permit application is included in the existing permit under 15A NCAC 02Q .0504. CCGF has satisfied the requirement to submit a permit application. Therefore, references to 02Q .0501(b)(2) and 02Q .0504 will be removed from the permit.

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

As CCGF noted in both applications .21A and .22A, the existing permit includes a reference to 40 CFR Part 97, Subpart BBBBB. This rule no longer applies in North Carolina. For a discussion of why 40 CFR Part 97, Subpart BBBBB no longer applies in North Carolina, see 40 CFR 52.1784 and 81 FR 74586. References to 40 CFR Part 97, Subpart BBBBB will be removed from the permit.

In the existing permit, references to CSAPR are listed as “Federal-enforceable Only.” This is an error because all portions of a Title V permit issued by DAQ must also be enforceable by DAQ. Therefore, the term “Federal-enforceable Only” will not be associated with CSAPR in the new permit.

The changes to the specific condition for CSAPR in the Title V permit will not affect CCGF’s compliance requirements under CSAPR.

c. Correction to permitted emission sources and control devices

Each of the four turbines at this facility use water injection to control NOx emissions while firing fuel oil. Water injection in a combustion turbine is considered a control device. However, water injection is not explicitly listed as a control device in the list of permitted emission sources in the existing permit. This omission will be corrected in the permit. Note that this change does not reflect a physical change at the facility and will not change CCGF’s compliance requirements.

d. Changes to be addressed during Title V permit renewal

During internal review of the initial draft of the new Title V permit, two issues with the existing permit were noted. As discussed below, these issues will be resolved during the next Title V permit renewal.

i. Continuous Emission Monitoring System (CEMS) requirements under 02D .1418

In the existing permit, CCGF is required to demonstrate compliance with the NOx limit in 02D .1418 by operating a NOx CEMS (see condition 2.1 A.3 of the existing permit). The existing permit requires that the CEMS be operated according to the requirements of NSPS Subpart KKKK.

According to 15A NCAC 02D .1404(e), a facility is required to use data substitution when using a CEMS to demonstrate compliance with a NOx limit under any limit in Subchapter 02D .1400. NSPS Subpart KKKK does not address data substitution when operating a NOx CEMS. Therefore, the existing permit is silent regarding data substitution when demonstrating compliance with the limit under 02D .1418.

The limit for NOx under 02D .1418 is the same as the NOx BACT limit under PSD:

While firing natural gas:	9 ppmvd at 15% O_2 [24-hour average]
While firing fuel oil	42 ppmvd at 15% O_2 [24-hour average]
All fuels	22,770 pounds per day
	1,306 tons per year

02D .1404(e) requires data substitution using the methods in 40 CFR Part 75. This data substitution method is generally used to comply with a long-term limit (e.g., tons per year). It is unclear how, or if, the 40 CFR Part 75 method would apply to shorter term limits.

The application of data substitution may change additional requirements under 02D .1418. Reevaluating compliance requirements under 02D .1418 is outside the scope of this Part 2 significant modification. This issue will be reviewed during the next Title V permit renewal.

ii. Continuous Emission Monitoring System (CEMS) requirements under 02D .0530

In the existing permit, CCGF is subject to several Best Available Control Technology limits (BACT limits) under 15A NCAC 02D .0530 "Prevention of Significant Deterioration" (PSD). The limits are listed in a table in Specific Condition 2.2 A.1.a and b. The table in 2.2 A.1.a includes the following two footnotes:

3. 24-hour rolling average is calculated using only actual operating hours (periods of zero emissions when not operating are not included). A valid hourly emission rate shall be calculated for each hour in which at least two NOx concentrations are obtained at loads above 60 percent for gas and 70 per cent for oil at least 15 minutes apart.
4. Compliance with the BACT limits shall be based on a 3-run average of a stack test. Any use of CEMS data for demonstrating compliance with BACT for any pollutants will require reevaluation of applicable BACT limits.

These footnotes appear contradictory. Footnote 4 disallows the use of CEMS without reevaluating BACT limits, while Footnote 3 discusses calculating a 24-hour rolling average using data collected on an hourly basis (ostensibly using a CEMS to gather the data). Furthermore, the limit under 02D .1418 is explicitly equal to the BACT limit in Table 2.2 A.1.a. As discussed above, CCGF is required to use a CEMS to comply with 02D .1418. As a result, it appears the Title V permit both requires and disallows the use of CEMS for compliance with the same emission limit.

CCGF has suggested[2] that Footnote 4 should never have applied to the NOx BACT limits. CCGF has always been required to operate a NOx CEMS (required by both NSPS Subpart KKKK and 40 CFR Part 75). Instead, CCGF states that Footnote 3 applies to NOx, and Footnote 4 applies to all other emission limits in Table 2.2 A.1.a. If this were true, there would be no inconsistency regarding the use of CEMS.

The first Title V permit for this facility was issued on September 10, 2009. In DAQ's application review, DAQ acknowledged that CCGF would be required to use a CEMS for NOx emissions to comply with the Acid Rain Permit (a.k.a. 40 CFR Part 75)[3], but does not include any clarification regarding the origin or applicability of Footnotes 3 and 4 to Table 2.2 A.1.a. CCGF's original permit application may contain more information, but a hard copy of that application is not available in DAQ's Central Files.

Reevaluating how CCGF complies with the NOx limit in Table 2.2 A.1.a is outside the scope of this Part 2 significant modification. This issue will be reviewed during the next Title V permit renewal.

[2] Email from Scott McMillian to Russell Braswell, dated February 3, 2022.
[3] See DAQ's application review for Air Quality Permit 09881R00, issued September 10, 2009 (page 20).

e. Summary of changes

The following changes were made to Air Permit No. 09881T09:*

Page No.	Section	Description of Changes
Throughout	Throughout	• Updated dates and permit numbers. • Updated permit format to DAQ latest standard. Formatting changes are not expected to impact the Permittee’s compliance requirements.
5	1.	• Moved “water injection” to the control device column and out of the emission source description for ES1 through ES4. Noted that water injection while firing fuel oil is a control device. This does not reflect any physical change at the facility. This change is only for clarity.
9	2.1 A.3.c	• Removed duplicate paragraph. This paragraph was likely included as a copy/paste error. This paragraph referenced visible emissions; there are no visible emission limits in Section 2.1 A.3.
n/a	2.2 B.3 (former)	• Removed this section because the Permittee has completed the requirements under 02Q .0504.
n/a	2.2 C.3 (former)	• Removed this section because the Permittee has completed the requirements under 02Q .0504.
18	2.4	• Removed note that stated CSAPR is “Federal-Enforceable Only.” • Removed reference to 40 CFR Part 97, Subpart BBBBB because this rule no longer applies within North Carolina.
19	3. (new)	• Created this section. • Moved the list of insignificant activities (formerly attached to the cover letter) to this section. This is part of updating the format of Title V permits and does not reflect a physical change at the facility or a change in compliance requirements.
20	4. (new)	• Created this new section for the General Conditions. • Updated General Conditions to v6.0.

* This list is not intended to be a detailed record of every change made to the permit but a summary of those changes.

5. Compliance Status and Other Regulatory Concerns:

- *Compliance status*: This facility was most recently inspected on June 16, 2021 by Denise Hayes. CCGF appeared to be in compliance with the Title V permit during that inspection.

- *Compliance history*: CCGF was issued a Notice of Violation (NOV) on February 15, 2019 because the sulfur content of natural gas fired at the facility was above an emission limit in the Title V permit. DAQ considers this matter resolved as of March 1, 2019. No fine was assessed. Note that the existing permit does not include a natural gas sulfur content limit.

- *Application fee*: Applications for significant modification require an application fee. The appropriate fee was received on May 5, 2021 (application .21A) and February 7, 2022 (application .22A).

- *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 **NOT** required for this 2-step significant modification because that requirement has been addressed with application .19B and .19C (see Attachment 1) and .21A and .22A (see Attachment 2).

- *Zoning*: A Zoning Consistency Determination per 15A NCAC 02Q .0304(b) was **NOT** required for this this Title V or Title IV permit renewal. The requirement for a PE Seal for the 2-step significant modification was addressed with application .19B and .19C (see Attachment 1) and .21A and .22A (see Attachment 2).

6. 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 (2020). The HAP emitted in the largest quantity from the facility is formaldehyde.

The completion of the 2-step significant modification 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 1and Attachment 2 for a summary of emission changes associated with those modifications.

7. Draft Permit Review Summary

Initial draft: An initial draft of the Title V permit an application review were prepared by Connie Horne and sent to RCO staff on November 22, 2021 and to SSCB, MRO, and CCGF staff on December 2, 2021.

SSCB Comment 1: The facility is using a NOx CEMS to comply with the NOx BACT limit. In that case we need to add additional permit conditions for CEMS monitoring and reporting requirements for missing data substitution, %MD, EERs etc.

Response: It is unclear if the Title V permit should allow or disallow the use of NOx CEMS to comply with the NOx BACT limit. Further research will be required. This issue will be resolved during the next Title V permit renewal.

SSCB Comment 2: The units subject to 02D .1418 (Section 2.1 A.3) that uses CEMS, are required to do the monitoring as per 02D .1404 as specified in 02D .1418(d) instead of NSPS KKKK, and 02D .1404(e) requires missing data procedure as per Part 75.

Response: It is unclear how the data substitution requirement will change the facility's compliance requirements. Given the question above (that is, if the facility is allowed to use a NOx CEMS at all for the NOx BACT limit), this issue requires further research and is outside the scope of the Part 2 significant modification. This issue will be resolved during the next Title V permit renewal.

SSCB Comment 3: Please indicate Water Injection as control device in the emission sources table, where it says control device N/A.

Response: This change will not affect CCGF's compliance requirements. Therefore, this change will be made at this time.

No other comments were received on the initial draft. Based on comments received, responsibility for these applications were transferred to Russell Braswell, and a new draft of the application and review were prepared.

Second draft: In order to address the above comments, a second version of the draft permit and application review were prepared for RCO staff. The only comments on the second draft pointed out typos and formatting errors.

8. 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 XXXXX.
- The Public Notice period ended on XXXXX.
- The EPA Review period ended on XXXXX.

9. 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. 09881T10. MRO has received a copy of this permit and submitted comments that were incorporated as described in Section 7.

Recommend addressing the issues described in Section 4.d during the next Title V permit renewal.

Attachment 1 to Review of Applications 2300372.21A & .22A
Cleveland County Generating Facility
Review of Applications 2300372.19B &.19C

Below is DAQ's review of applications 2300372.19B & .19C. In response to these applications, DAQ issued 09881T08.

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

Review Engineer: Russell Braswell Review Engineer's Signature: Date: [Signed by Russell Braswell on the Permit Issue Date]	**Comments / Recommendations:** **Issue** 09881/T08 **Permit Issue Date:** October 22, 2019 **Permit Expiration Date:** June 30, 2023 (no change)

DRAFT

1. Purpose of Application:

Cleveland County Generating Facility ("CCGF") currently operates a power plant in Cleveland County under Title V permit 09881T07 ("the existing permit"). The power plant consists of four simple-cycle turbines. CCGF plans to perform minor upgrades to two of the turbines. As a result of the upgrades, the maximum heat input and overall utilization of the turbines is projected to increase, which will increase actual air emissions from the facility. CCGF has submitted these applications in order to demonstrate that the planned upgrades will not trigger a review under 02D .0530 "Prevention of Significant Deterioration".

These applications were received at approximately the same time and were consolidated for permit processing. They are being processed under 02Q .0501(b)(2), which will allow the permit to be issued before going through Public Notice and EPA Review. CCGF will be required to submit a second application within one year of finishing the planned upgrades.

2. Facility Description:

This facility is a power plant that operates four simple-cycle combustion turbines. The turbines are all the same model (Siemens SGT6-500F). The primary fuel for the turbines is natural gas, but the facility also burns No. 2 fuel oil. Each of the four turbines are subject to the requirements of 02D .0530 "Prevention of Significant Deterioration" ("PSD"). The facility is limited to 26,520,000 million Btu of heat input per rolling 12-month period.

3. Application Chronology:

- July 31, 2019 — Application .19B received in Raleigh Central Office.
- August 7, 2019 — Application .19C received in Raleigh Central Office.
- August 15, 2019 — Zoning consistency determination received in Raleigh Central Office.
- August 20, 2019 — CCGF submitted an amendment to application .19B. This made minor changes to the emission calculations, but did not result in any substantial changes.
- August 28, 2019 — CCGF confirmed that this facility had not made any submissions to the North Carolina Utilities Commission regarding the upgrades proposed by applications .19B and .19C.

- September 3, 2019 — An initial draft of the permit and associated application review were sent to DAQ staff (Tom Anderson, Mark Cuilla, Samir Parekh, Denise Hayes) and CCGF staff (Scott McMillan). For a summary of comments received, see Attachment 2.
- October 16 , 2019 — Permit T07 issued in response to application .19A.
- October 17, 2019 — In a meeting with Tom Anderson (DAQ, Air Quality Analysis Branch Supervisor) and Scott McMillian, it was determined that additional air dispersion modeling would not be required for this application.
- October 22, 2019 — Permit issued.

4. Regulatory Overview:

CCGF is subject to several rules, but the only rule affected by the proposed upgrades is 02D .0530 "Prevention of Significant Deterioration". Compliance with other rules in the permit (e.g. 02D .0524 "New Source Performance Standards") will not be affected by the upgrades.

5. Discussion:

a. Project description:

In the permit applications, CCGF described the need and nature of the proposed upgrades:

> "During normal operation, components of combustion turbines are exposed to stresses. To ensure proper operation of these units, the equipment manufacturer recommends inspections and parts replacement on a routine basis. The typical hot gas path ("HGP") maintenance outage involves replacing parts…and subsequent tuning of the turbine operations and other ancillary equipment. The vendor has recommended during the upcoming maintenance outage that [CCGF] replace certain parts with as newer version of each component that is compatible with the Advanced Ultra-Low NOx 3.0 ("ULN 3.0") combustion system…The ULN 3.0 upgrade will allow the unit to increase intervals between outages and allow the unit to operate at higher firing temperatures to increase the unit's generating efficiency and total electrical output."

As a result of the above, CCGF expects air emissions from Unit 2 and Unit 3 to increase. CCGF is evaluating whether to install the same upgrade at the other two units (Unit 1 and Unit 4), but at this time no final decision has been made for either unit. The ULN 3.0 upgrades will take place during two pre-scheduled outages.

In an email received September 13, 2019, CCGF stated that the heat input capacity of Unit 2 and Unit 3 would increase to 2,321 million Btu per hour firing natural gas and 2,179 million Btu per hour while firing oil.

Because Unit 2 and Unit 3 are subject to PSD requirements, CCGF must demonstrate that any modifications to these sources do not trigger a new PSD review. As allowed by 02D .0530(u), CCGF has calculated the projected actual emissions from each unit post upgrade to show that each project does not cause a significant emission increase as defined in 40 CFR 51.166(b)(23).

Before calculating projected actual emissions, it must be determined if the upgrades to Unit 2 and Unit 3 should be considered a single project or evaluated separately:

b. Aggregation of projects for PSD permitting:

In the previous three years, CCGF has submitted five permit applications.

The application states that the Unit 2 and Unit 3 upgrades should be considered separate projects under PSD because they do not meet the definition of "substantially related" as mentioned in EPA's rules on project aggregation. In addition, any recent modifications to the facility should be examined.

"Substantially related" is a determination initially suggested by EPA in the "3M Memo"[1,2], affirmed on January 15, 2009 (74 FR 2376; "the 2009 action"), and reaffirmed on November 15, 2018 (83 FR 57324; "the 2018 action"). As a general rule, projects that are not substantially related should be considered separately when determining applicability of PSD/NSR. In order to determine if two or more projects are substantially related, EPA has suggested looking at the different factors regarding the specific project, such as the timing of activities, technical dependence, and economic dependence.

1. Time between projects:

   EPA has suggested that time between projects is an important factor when determining if projects are substantially related. In the 2009 action, EPA stated that three years between projects is generally a long enough period of time between projects to be considered separate. In the previous three years, CCGF has submitted five permit applications (excluding applications .19B and .19C). The following is a brief overview of these recent applications:

Table 1: Recent permit applications

Application	Corresponding Permit Revision	Description
.16A	T04, issued July 19, 2016	Removed turbines ES-05 and ES-06 from the permit because these units were never constructed. The hours of operation that were previously assigned to these units were split amongst the remaining turbines. Did not change potential/actual emissions. Did not require a physical change.
.17A	T05, issued March 29, 2017	Allowed co-firing of natural gas during periods when the turbines were both firing oil and starting up or shutting down. This practice was recommended by the turbine manufacturer. Did not change potential/actual emissions. Did not require a physical change.
.18A	T06, issued July 9, 2018	Renewed the Title V permit. Did not change potential/actual emissions. Did not require a physical change.
.18B		Renewed the Title IV permit. Did not change potential/actual emissions. Did not require a physical change.

[1] Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, OAQPS, to George T. Czerniak, Chief, Air Enforcement Branch, EPA Region 5, titled, "Applicability of New Source Review Circumvention Guidance to 3M—Maplewood, Minnesota".

[2] In the 3M Memo, EPA used the term "intrinsic relationship". In *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Aggregation; Reconsideration* (83 FR 57324), EPA stated that this term is functionally synonymous with "substantially related" (*see* 83 FR 57331). "Substantially related" will be used in this application review.

Application	Corresponding Permit Revision	Description
.19A	T07 issued October 16, 2019	Removed the sulfur content limit for natural gas because the natural gas supplier could not comply with the limit and review of recent BACT determinations showed that such a limit was not necessary or standard practice. Did not require a physical change.

Of all the recent applications, only .19A resulted in a change in potential emissions from the facility. Therefore, only .19A will be examined for potential aggregation, in addition to .19B and .19C.

Additionally, EPA has qualified the 3-year guideline mentioned in the 2009 action. In the 2018 action, EPA stated "Previous agency statements can be taken out of context or misunderstood when reviewing projects having a different set of facts. For example, while the [3M Memo] was considered by some as the EPA's guiding policy on project aggregation, <u>parties could certainly misconstrue portions of that statement to suggest that all projects occurring within the same timeframe should be aggregated</u>…" (83 FR 57330, emphasis added). Therefore, the fact that the Unit 2 and Unit 3 upgrades will occur at approximately the same time, and near to the fuel sulfur content limit change, is by itself not sufficient evidence to require project aggregation. The technical and economic dependencies of these projects must be examined.

2. <u>Technical dependence:</u>

The 2009 action states "activities occurring in unrelated portions of a major stationary source (e.g., a plant that makes two separate products and has no equipment shared among the two processing lines) [may] not be substantially related", and "[t]o be 'substantially related,' there should be an apparent interconnection—either technically or economically—between the physical and/or operational changes…" (74 FR 2378). The 2018 action also states, "Such an approach—i.e. to aggregate projects simply because they may occur close in time or may support the same overall purpose of the facility—fails to take proper account of the actual interrelationship of activities" (83 FR 57330).

On the surface, the ULN 3.0 upgrades for Unit 2 and Unit 3 appear to be technically related, because they are essentially identical units, with identical planned upgrades, serving the same purpose, located at the same facility. However, according to the application, Units 2 and 3 operate totally independent of each other, and the successful upgrade of one unit does not depend on the successful upgrade of the other. Units 2 and 3 do not share common parts. The facility operates two additional units (Units 1 and 4) that are not currently scheduled for an upgrade, demonstrating that each turbine can be upgraded independently of the others. Therefore, the projects for Unit 2 and Unit 3 do not appear to share a technical dependence.

On the surface, the ULN 3.0 upgrades for Unit 2 and Unit 3 also appear to be technically related to the change in the fuel sulfur content limit given that natural gas is the primary heat source for these turbines. However, Unit 1 and Unit 4 will continue to operate without the ULN 3.0 upgrades, demonstrating that the upgrade is technically independent from the fuel sulfur content.

3. <u>Economic dependence:</u>

The application specifically states "From an economic perspective, the cost for each project is independent from the other, each project is expected to return economic benefits to the facility regardless of whether any other project is completed, and the decision to implement the upgrade at one unit did not have any effect on the outcome of the economic evaluation of the project for the other unit." In addition, the upgrades will be performed during shutdowns that are already scheduled, and will occur regardless of one or both upgrades being completed. Based on this information, it appears the two projects do not appear to share an economic dependence.

4. Conclusion:

Based on the information provided in the application, DAQ agrees that the upgrade projects for Unit 2 and Unit 3 and the change to the limit of fuel sulfur content should each be considered separately for the purposes of NSR aggregation. Note that this determination is only for these specific units, located at this specific facility, and undergoing these specific upgrades.

c. Using projected actual emissions to avoid PSD permitting

As stated above, in order to avoid a PSD review for a modification, the applicant must demonstrate that the modification does not increase emissions of any pollutant above its significance threshold. For each of the Unit 2 and Unit 3 upgrades, CCGF has performed the following calculations: calculate the baseline actual emissions, calculate the projected actual emissions, and calculate the projected change in emissions.

1. Calculate the baseline for each unit

15A NCAC 02D .0530(b)(1) defines the baseline actual emissions as the average annual emission rate of that pollutant during "…any consecutive 24-month period selected by the owner or operator within the five-year period immediately preceding the date that a complete permit application is received by the Division…" The application establishes the following baseline periods[3]:

Table 2: Baseline heat input for Unit 2 and Unit 3

Source	Pollutant	Baseline		
		Begin	End	Actual heat input
Unit 2	NOx	June 2016	May 2018	2,578,728
	All other	October 2015	September 2017	2,654,885
Unit 3	NOx	September 2015	August 2017	2,729,837
	All other	July 2015	June 2017	2,738,450

[3] Note that 02D .0530(b)(1)(A)(v) allows for a different baseline period to be chosen for each pollutant.

Table 3: Baseline actual emissions for Unit 2 and Unit 3[4]

Pollutant	Emission Factor (lb/MMBtu) Unit 2	Emission Factor (lb/MMBtu) Unit 3	Baseline Actual Emissions (ton/yr) Unit 2	Baseline Actual Emissions (ton/yr) Unit 3
NOx	3.21E-02	3.10E-02	41.44	42.28
CO	2.28E-02	2.25E-02	30.26	30.85
PM	8.72E-03	8.41E-03	11.57	11.52
PM10	8.72E-03	8.41E-03	11.57	11.52
PM2.5	8.72E-03	8.41E-03	11.57	11.52
VOC	6.86E-03	6.82E-03	9.10	9.33
SO_2	6.04E-04	6.03E-04	0.80	0.83

Baseline Heat Input (MMBtu/yr)	
Unit 2, NOx	2,578,728
Unit 2, other	2,654,885
Unit 3, NOx	2,729,837
Unit 3, other	2,738,450

During the baseline periods, Unit 2 burned 99.3% natural gas and Unit 3 burned 99.8% natural gas. The remainder was made up by No. 2 fuel oil. CCGF derived the emission factors used in the analysis based on CEMS data, permit limits, and AP-42. See Attachment 1 for the calculations performed by CCGF for the emission factors.

2. Calculate the projected actual emissions for each unit

CCGF estimated the expected growth in utilization of the facility based on its proprietary dispatching model, which its parent company Southern Power Company uses to predict utilization and make suitable business decisions. CCGF used the dispatching model to analyze the next five years. Based on the dispatching model, the 12-month highest heat input for the two units can be estimated:

Table 4: Projected heat input for Unit 2 and Unit 3

Source	Projected highest 12-month heat input		
	Begin	End	Projected heat input (MMBtu/yr)
Unit 2	June 2023	May 2024	2,757,140
Unit 3	June 2024	May 2025	2,963,417

In the application, and again in an in-person meeting on October 18, 2019, CCGF stated that emissions on a lb/MMBtu basis are not expected to change. Therefore, the projected actual emissions can be calculated using the existing emission factors and the projected heat input:

[4] Note that 02D .2609(a) requires that particulate emissions be determined using EPA Methods 5 *and* 202. i.e. "PM" and "particulate matter" is the sum of filterable and condensable particulates.

Table 5: Projected actual emissions for Unit 2 and Unit 3

Pollutant	Emission Factor (lb/MMBtu) Unit 2	Emission Factor (lb/MMBtu) Unit 3	Projected Actual Emissions (ton/yr) Unit 2	Projected Actual Emissions (ton/yr) Unit 3
NOx	3.21E-02	3.10E-02	44.30	45.90
CO	2.28E-02	2.25E-02	31.42	33.38
PM	8.72E-03	8.41E-03	12.02	12.47
PM10	8.72E-03	8.41E-03	12.02	12.47
PM2.5	8.72E-03	8.41E-03	12.02	12.47
VOC	6.86E-03	6.82E-03	9.45	10.10
SO_2	6.04E-04	6.03E-04	0.83	0.89

Projected Heat Input (MMBtu/yr)	
Unit 2	2,757,140
Unit 3	2,963,417

3. <u>Compare the Projected Change in Emissions to the Significance Level</u>

   Because emissions on a lb/MMBtu basis are not expected to change (i.e. the emission factors are not expected to change), the projected increase in annual emissions will be solely based on the difference in baseline heat input and projected future heat input.

Table 6: Comparison of Baseline to Projected Actual Emissions for Each Project

Pollutant	Baseline Emissions (ton/yr) Unit 2	Baseline Emissions (ton/yr) Unit 3	Projected Actual (ton/yr) Unit 2	Projected Actual (ton/yr) Unit 3	Change in Emissions (ton/yr) Unit 2	Change in Emissions (ton/yr) Unit 3	Significant Emission Increase (ton/yr)	SEI Exceeded?
NOx	41.44	42.28	44.30	45.90	2.87	3.62	40	No
CO	30.26	30.85	31.42	33.38	1.17	2.53	100	No
PM	11.57	11.52	12.02	12.47	0.45	0.95	25	No
PM10	11.57	11.52	12.02	12.47	0.45	0.95	15	No
PM2.5	11.57	11.52	12.02	12.47	0.45	0.95	10	No
VOC	9.10	9.33	9.45	10.10	0.35	0.77	40	No
SO_2	0.80	0.83	0.83	0.89	0.03	0.07	40	No

   As can be seen in Table 6, the projected change in emissions for each project are less than their respective significance levels. Therefore, neither project will trigger a new PSD review.

d. <u>Compliance requirements for use of projected actual emissions:</u>

In order to demonstrate that the projected actual emissions included in the application were accurate, CCGF will monitor emissions from Unit 2 and Unit 3 for five years following the completion of each upgrade. The annual emissions will be compared to the projected emissions. If there is a discrepancy, CCGF may be required to again demonstrate that the upgrade projects did not trigger a PSD review.

The Title V permit will be modified to include two specific conditions (one for each upgrade project) for 15A NCAC 02D .0530(u) "Use of Projected Actual Emissions". The projected annual emissions will be included in the permit for future comparison. Note that this does not constitute an emission limit, and that an exceedance of these projected emissions does not necessarily indicate a violation.

6. Facility Emissions Review

Due to the upgrade, the maximum heat input capacity of Unit 2 and Unit 3 will each increase by 111 million Btu per hour while firing natural gas and 50 million Btu per hour while firing fuel oil. This increase is not expected to change potential emissions from the facility because Unit 2 and Unit 3 are limited by annual heat input (see Specific Condition 2.2 A.1.d). Actual emissions from this facility on an annual basis are expected to change according to the analysis above.

PSD Increment Tracking for this facility was initially based on facility-wide maximum potential operations of 26,520,000 million Btu per rolling 12-month period. This proposed upgrade will not increase the facility-wide potential operations, so PSD Increment Tracking will not be affected.

See the first page of this review for a summary of actual emissions reported by this facility.

7. Other Regulatory Concerns

- A zoning consistency determination was received for these applications on August 15, 2019.
- A PE seal was not required for this permit application.
- A specific permit condition for 15A NCAC 02Q .0504 will be added to the permit. This condition will require the submittal of an additional Title V permit application within one year of completing these upgrades.
- In an email received September 13, 2019, CCGF recommended removing the term "full-load equivalent hours" from Specific Condition 2.2 A.1. This term was only a convenient reference, not an enforceable limit. This reference will no longer be accurate given the slight increase in heat input capacity for Unit 2 and Unit 3. The enforceable limits (e.g. 26,520,000 million Btu per rolling 12-month period) will not be changed.

8. Recommendations

Issue permit 09881T08.

Attachment 1 to Review of Applications 2300372.19B and .19C
Cleveland County Generating Facility

Baseline and Emission Factor Calculations

The following calculations were performed by CCGF and included in the applications as Attachments A and B

Baseline calculations, Unit 2

CEMS Heat input (mmBtu) and NOx (tons)			
Year	Month	NOx tons	Heat Input
2015	October	6.709	452,977.3
2015	November	4.244	277,664.5
2015	December	0.009	202.8
2015	January	1.746	22,383.3
2015	February		
2015	March		
2016	April	1.099	75,761.5
2016	May	0.034	877.8
2016	June	3.966	271,287.1
2016	July	7.132	494,193.0
2016	August	8.650	576,571.6
2016	September	7.279	481,014.3
2016	October	6.211	414,998.0
2016	November	1.608	101,452.2
2016	December	0.695	42,112.7
2016	January	0.352	4,954.8
2016	February	0.367	22,973.4
2016	March	2.367	119,787.2
2017	April	4.169	284,316.5
2017	May	3.320	224,858.4
2017	June	3.487	236,959.7
2017	July	6.434	439,908.1
2017	August	6.282	434,605.3
2017	September	4.824	329,909.5
2017	October	2.807	188,788.4
2017	November	3.893	257,995.2
2017	December	0.284	19516.488
2018	January	7.148	104689.849
2018	February	0	0
2018	March	0.003	75.145
2018	April	0	0
2018	May	1.594	106488.4
Annual Average	October 2015 - September 2017		2,654,885
	June 2016 - May 2018	41.436	2,578,728

Baseline calculations, Unit 3

CEMS Heat input (mmBtu) and NOx (tons)			
Year	Month	NOx tons	Heat Input
2015	July	7.765	515,488.0
2015	August	6.307	410,980.2
2015	September	4.892	315,330.9
2015	October	8.516	554,529.4
2015	November	4.383	278,124.1
2015	December		
2016	January		
2016	February		
2016	March		
2016	April	1.753	115,019.3
2016	May	0.554	34,966.7
2016	June	5.109	332,945.0
2016	July	9.100	603,080.5
2016	August	8.758	568,341.2
2016	September	7.160	464,193.6
2016	October	5.679	370,718.5
2016	November	2.105	132,049.7
2016	December	0.168	9,160.1
2017	January	0.003	72.5
2017	February	0.201	12,348.5
2017	March	1.834	103,053.1
2017	April	4.330	277,994.3
2017	May	3.262	211,366.3
2017	June	2.658	167,137.8
2017	July	7.366	474,388.1
2017	August	6.725	434,855.0
Annual Average	July 2015 - June 2017		2,738,450
	September 2015 - August 2017	42.278	2,729,837

Emission factor calculations, Unit 2

Cleveland County 2 Emission Factors

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source/Notes:
NOx	0.0321	CEMS - 24-month annual average from Jun. 2016 to May 2017 - (See Appendix A)
SO2	0.0006	CEMS - 24-month annual average from Oct. 2015 to Sep. 2017
CO	0.023	Permit Limit for NG + oil - weighted avg - (See calc. backup below)
VOC	0.0069	Permit Limit for NG + oil - weighted avg - (See calc. backup below)
PMf	0.0019	AP-42 gas + oil weighted avg - (See calc. backup below)
PM10	0.0087	Permit limit(s) for NG + oil - weighted avg - (See calc. backup below)
PM2.5	0.0087	Permit limit(s) for NG + oil - weighted avg - (See calc. backup below)

lb/MMBtu Emission Factor Calculation Backup

Fuel Type	Baseline data (October 2015 - September 2017)		Permit Limit (equiv. lb/mmBtu)		AP42 Table 3.1-2a (lb/mmBtu)		Permit Limit (lb/mmBtu)
	mmBtu	% HI	CO	VOC	PM_filt.	PM_cond.	PM10 (PM2.5)
Natural Gas	5,270,274	99.3%	0.022	0.0068	0.0019	0.0047	0.0083
Oil	39,495	0.7%	0.071	0.014	0.0043	0.0072	0.0646

lb/mmBtu (Permit limit equivalent) = ppmvd (Permit Limit Limit)x10^{-6} * MW/385 * F_d * 20.9/(20.9-O_2%, dry)

lb/mmBtu (CO & VOC) = ((Permit limit eEquiv. lb/mmBtu gas)*(Baseline mmBtu gas)+(Permit limit Equiv.lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PMf) = ((AP-42 for lb/mmBtu gas)*(Baseline mmBtu gas)+(AP-42 for lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PM10 & 2.5) = ((Permit limit for lb/mmBtu gas)*(Baseline mmBtu gas)+(Permit limit for lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

Example Calculations:

CO lb/mmBtu (Permit Limit Equiv. NG) = 10 ppmvd * (12+16)/385 * 8710 * 20.9/(20.9-15) = 0.022

CO lb/mmBtu (NG + Oil Weighted avg.) = (0.022*5,465,906 + 0.071*10,993) / (5,465,906 + 10,993) = 0.023

Emission factor calculations, Unit 3

Cleveland County 3 Emission Factors

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source/Notes:
NOx	0.031	CEMS - 24-month annual average from Sep. 2015 to Aug. 2017 - (See Appendix A)
SO2	0.0006	CEMS - 24-month annual average from Jul. 2015 to Jun. 2017
CO	0.023	BACT for NG + oil - weighted avg - (See calc. backup below)
VOC	0.0068	BACT for NG + oil - weighted avg - (See calc. backup below)
PMf	0.0019	AP-42 gas + oil weighted avg - (See calc. backup below)
PM10	0.0084	Permit limit(s) for NG + oil - weighted avg - (See calc. backup below)
PM2.5	0.0084	Permit limit(s) for NG + oil - weighted avg - (See calc. backup below)

lb/MMBtu Emission Factor Calculation Backup

Fuel Type	Baseline data (July 2015 - Jun 2017)		BACT (equiv. lb/mmBtu)		AP42 Table 3.1-2a (lb/mmBtu)		Permit Limit (lb/mmBtu)
	mmBtu	% HI	CO	VOC	PM_filt.	PM_cond.	PM10 (PM2.5)
Natural Gas	5,465,906	99.8%	0.022	0.0068	0.0019	0.0047	0.0083
Oil	10,993	0.2%	0.071	0.014	0.0043	0.0072	0.0646

lb/mmBtu (BACT equivalent) = ppmvd (BACT Limit)x10^{-6} * MW/385 * F_d * 20.9/(20.9-O_2%, dry)

lb/mmBtu (CO & VOC) = ((BACT equiv. lb/mmBtu gas)*(Baseline mmBtu gas)+(BACT equiv. lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PMf) = ((AP-42 for lb/mmBtu gas)*(Baseline mmBtu gas)+(AP-42 for lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PM10 & 2.5) = ((Permit limit for lb/mmBtu gas)*(Baseline mmBtu gas)+(Permit limit for lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

Example Calculations:

CO lb/mmBtu (BACT Eqiv. NG) = 10 ppmvd * (12+16)/385 * 8710 * 20.9/(20.9-15) = 0.022

CO lb/mmBtu (NG + Oil Weighted avg.) = (0.022*5,465,906 + 0.071*10,993) / (5,465,906 + 10,993) = 0.023

Attachment 2 to applications 2300372.19B and .19C
Cleveland County Generating Facility

Comments Received on Initial Draft [of Permit 09881T08]

- Rahul Thaker, in person on September 9, 2019

  Issues discussed in this meeting:

  1. 02D .2609(a) defines the testing requirements for "particulate matter" as EPA Methods 5 *and* 202. Therefore, any reference to "PM" or "particulate matter" should include both filterable and condensable PM. This is not the case for PM10 and PM2.5, which are defined elsewhere.

     Response: I have calculated the condensable PM based on the emission factors provided.

  2. Minor corrections to the discussion of project aggregation under PSD.

     Response: I have corrected these issues.

  3. Minor typo corrections.

     Response: I have corrected these issues.

- Mark Cuilla, by email on September 4, 2019

  1. PSD Increment Tracking is based on actual emissions. Therefore, this modification should consume some increment.

     Response: I have calculated the PSD Increment Tracking based on actual emissions.

  2. Minor typos corrections in the draft permit and application review.

     Response: Fixed.

- Scott McMillan, by email on September 13, 2019 and September 23, 2019

  1. Suggested corrections to wording in application review.

     Response: I corrected these issues.

  2. Pointed out typos in the application review.

     Response: I corrected these issues.

  3. The planned upgrades will increase the heat input capacity of the turbines and the hourly PM emission rate. The permit should be updated.

     Response: I have updated the permit and addressed this in the application review.

  4. Because of the increase in heat input capacity, the term "full-load equivalent hours" is no longer accurate and should be removed from the permit.

Response: *I agree that this term is no longer relevant in the permit. Removing this term will not change the compliance requirements in the permit.*

5. The application review does not use the correct emission factors for the turbines. The numbers in the draft permit are therefore incorrect.

   Response: *I have corrected the application review and corresponding tables in the draft permit. We discussed the fact that North Carolina requires "PM" to include filterable* and *condensable. We agreed that the PM10 and PM2.5 emission factor would be acceptable for PM.*

6. PSD Increment Tracking does not need to be updated based on this application. The former PSD Increment Tracking had been calculated according to the facility's potential emissions, which are not changing as part of this application.

   Response: *I agree.*

Attachment 2 to Review of Applications 2300372.21A & .22A
Cleveland County Generating Facility
Review of Applications 2300372.20A & .20B

Below is DAQ's review of applications 2300372.20A & .20B. In response to these applications, DAQ issued 09881T09.

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

Review Engineer: Kevin Godwin **Review Engineer's Signature:** **Date:** 09/28/2020 *Kevin T. Godwin*	**Comments / Recommendations:** **Issue** 09881/T09 **Permit Issue Date:** 09/28/2020 **Permit Expiration Date:** 06/30/2023

I. Purpose of Application

Cleveland County Generating Facility ("CCGF") currently operates a power plant in Cleveland County, North Carolina under Title V permit 09881T08 ("the existing permit"). The power plant consists of four simple-cycle turbines. CCGF plans to perform minor upgrades to two of the turbines. As a result of the upgrades, the maximum heat input and overall utilization of the turbines is projected to increase, which will increase actual air emissions from the facility. CCGF has submitted these applications in order to demonstrate that the planned upgrades will not trigger a review under 02D .0530 "Prevention of Significant Deterioration".

These applications were received at approximately the same time and were consolidated for permit processing. Because this modification does involve a significant change to existing monitoring and recordkeeping requirements, it is a Significant Modification pursuant to 15A NCAC 02Q .0516. The applications are being processed under 02Q .0501(b)(2), which will allow the permit to be issued before going through Public Notice and EPA Review. CCGF will be required to submit a second application within one year of finishing the planned upgrades.

II. Facility Description:

This facility is a power plant that operates four simple-cycle combustion turbines. The turbines are all the same model (Siemens SGT6-500F). The primary fuel for the turbines is natural gas, but the facility also burns No. 2 fuel oil. Each of the four turbines are subject to the requirements of 02D .0530 "Prevention of Significant Deterioration" ("PSD"). The facility is limited to 26,520,000 million Btu of heat input per rolling 12-month period.

III. Application Chronology

May 7, 2020	Application .20A received in Raleigh Central Office (RCO),
May 19, 2020	Application .20B received in RCO,
June 21, 2020	In a meeting with Tom Anderson (DAQ, Air Quality Analysis Branch Supervisor) and Scott McMillian, it was determined that additional air dispersion modeling would not be required for these applications. The applications were deemed complete for processing.
August 27, 2020	Draft sent to DAQ Supervisor for review,
August 28, 2020	Draft sent to the Mooresville Regional Office (MRO) and the applicant for review,
September 2, 2020	MRO responded with no comments,
September 3, 2020	The applicant responded with minor comments,
September 10, 2020	Revised draft sent to the applicant,

September 21, 2020	Comments received from the applicant,
September 28, 2020	Permit issued.

IV. Statement of Compliance

The most recent compliance inspection was performed by Ms. Denise Hayes of the Mooresville Regional Office (MRO) on February 11, 2020. As stated in the inspection report dated February 11, 2020, “Based on my observations during this inspection, this facility appeared to be in compliance with the applicable air quality regulations.” The five-year compliance history is included in the inspection report as follows:

> The facility was issued a Notice of Violation on February 15, 2019 for exceeding the natural gas sulfur content limit contained in the condition for 2D .0530(h). The facility met with DAQ to determine a strategy to correct the limit in the permit and submitted an application to modify the permit. The new permit was issued on October 14, 2019.

V. Regulatory Overview:

CCGF is subject to several rules, but the only rule affected by the proposed upgrades is 02D .0530 "Prevention of Significant Deterioration". Compliance with other rules in the permit (e.g. 02D .0524 "New Source Performance Standards") will not be affected by the upgrades.

VI. Discussion:

a. <u>Project description:</u>

In the permit applications, CCGF described the need and nature of the proposed upgrades:

> "During normal operation, components of combustion turbines are exposed to stresses. To ensure proper operation of these units, the equipment manufacturer recommends inspections and parts replacement on a routine basis. The typical hot gas path ("HGP") maintenance outage involves replacing parts…and subsequent tuning of the turbine operations and other ancillary equipment. The vendor has recommended during the upcoming maintenance outage that [CCGF] replace certain parts with as newer version of each component that is compatible with the Advanced Ultra-Low NOx 3.0 ("ULN 3.0") combustion system…The ULN 3.0 upgrade will allow the unit to increase intervals between outages and allow the unit to operate at higher firing temperatures to increase the unit's generating efficiency and total electrical output."

As a result of the above, CCGF expects air emissions from Unit 1 and Unit 4 to increase. The ULN 3.0 upgrades will take place during two pre-scheduled outages. According to the application, the heat input capacity of Unit 1 and Unit 4 will increase to 2,321 million Btu per hour firing natural gas and 2,179 million Btu per hour while firing oil. In addition to Units 1 and 4, the facility submitted applications for Units 2 and 3 in 2019. The applications for Units 2 and 3 were approved with the issuance of Permit No. 09881T08 on October 22, 2019. Although the projects are similar in nature and timing, SPC is submitting separate permit applications for each upgrade because they constitute separate projects, in that they are not substantially related from an economic or technical perspective.

Because Unit 1 and Unit 4 are subject to PSD requirements, CCGF must demonstrate that any modifications to these sources do not trigger a new PSD review. As allowed by 02D .0530(u), CCGF has calculated the projected actual emissions from each unit post upgrade to show that each project does not cause a significant emission increase as defined in 40 CFR 51.166(b)(23).

Before calculating projected actual emissions, it must be determined if the upgrades to Unit 1 and Unit 4 should be considered a single project or evaluated separately.

b. <u>Aggregation of projects for PSD permitting:</u>
In the previous three years, CCGF has submitted six permit applications.

The application states that the Unit 1 and Unit 4 upgrades should be considered separate projects under PSD because they do not meet the definition of "substantially related" as mentioned in EPA's rules on project aggregation. In addition, any recent modifications to the facility should be examined.

"Substantially related" is a determination initially suggested by EPA in the "3M Memo"[1,2], affirmed on January 15, 2009 (74 FR 2376; "the 2009 action"), and reaffirmed on November 15, 2018 (83 FR 57324; "the 2018 action"). As a general rule, projects that are not substantially related should be considered separately when determining applicability of PSD/NSR. In order to determine if two or more projects are substantially related, EPA has suggested looking at the different factors regarding the specific project, such as the timing of activities, technical dependence, and economic dependence.

1. <u>Time between projects:</u>
EPA has suggested that time between projects is an important factor when determining if projects are substantially related. In the 2009 action, EPA stated that three years between projects is generally a long enough period of time between projects to be considered separate. In the previous four years, CCGF has submitted six permit applications (excluding applications .20A and .20B). The following is a brief overview of these recent applications:

Table 1: Recent permit applications

Application	Corresponding Permit Revision	Description
.16A	T04, issued July 19, 2016	Removed turbines ES-05 and ES-06 from the permit because these units were never constructed. The hours of operation that were previously assigned to these units were split amongst the remaining turbines. Did not change potential/actual emissions. Did not require a physical change.
.17A	T05, issued March 29, 2017	Allowed co-firing of natural gas during periods when the turbines were both firing oil and starting up or shutting down. This practice was recommended by the turbine manufacturer. Did not change potential/actual emissions. Did not require a physical change.
.18A	T06, issued July 9, 2018	Renewed the Title V permit. Did not change potential/actual emissions. Did not require a physical change.
.18B		Renewed the Title IV permit. Did not change potential/actual emissions. Did not require a physical change.

[1] Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, OAQPS, to George T. Czerniak, Chief, Air Enforcement Branch, EPA Region 5, titled, "Applicability of New Source Review Circumvention Guidance to 3M—Maplewood, Minnesota".

[2] In the 3M Memo, EPA used the term "intrinsic relationship". In *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Aggregation; Reconsideration* (83 FR 57324), EPA stated that this term is functionally synonymous with "substantially related" (*see* 83 FR 57331). "Substantially related" will be used in this application review.

Application	Corresponding Permit Revision	Description
.19A	T07 issued October 16, 2019	Removed the sulfur content limit for natural gas because the natural gas supplier could not comply with the limit and review of recent BACT determinations showed that such a limit was not necessary or standard practice. Did not require a physical change.
.19B and .19C	T08 Issued October 22, 2019	Included a condition pertaining to 15A NCAC 02D .0530(u) for Units 2 and 3.

Of all the recent applications, only .19A resulted in a change in potential emissions from the facility. Therefore, only .19A will be examined for potential aggregation, in addition to .19B, .19C, .20A and .20B.

Additionally, EPA has qualified the 3-year guideline mentioned in the 2009 action. In the 2018 action, EPA stated "Previous agency statements can be taken out of context or misunderstood when reviewing projects having a different set of facts. For example, while the [3M Memo] was considered by some as the EPA's guiding policy on project aggregation, <u>parties could certainly misconstrue portions of that statement to suggest that all projects occurring within the same timeframe should be aggregated</u>…" (83 FR 57330, emphasis added). Therefore, the fact that the Unit 2 and Unit 3 upgrades will occur at approximately the same time, and near to the fuel sulfur content limit change, is by itself not sufficient evidence to require project aggregation. The technical and economic dependencies of these projects must be examined.

2. <u>Technical dependence:</u>
The 2009 action states "activities occurring in unrelated portions of a major stationary source (e.g., a plant that makes two separate products and has no equipment shared among the two processing lines) [may] not be substantially related", and "[t]o be 'substantially related,' there should be an apparent interconnection—either technically or economically—between the physical and/or operational changes…" (74 FR 2378). The 2018 action also states, "Such an approach—i.e. to aggregate projects simply because they may occur close in time or may support the same overall purpose of the facility—fails to take proper account of the actual interrelationship of activities" (83 FR 57330).

On the surface, the ULN 3.0 upgrades for Unit 1 and Unit 4 appear to be technically related, because they are essentially identical units, with identical planned upgrades, serving the same purpose, located at the same facility. However, according to the application, Units 1 and 4 operate totally independent of each other, and the successful upgrade of one unit does not depend on the successful upgrade of the other. Units 1 and 4 do not share common parts, demonstrating that each turbine can be upgraded independently of the others. Therefore, the projects for Unit 1 and Unit 4 do not appear to share a technical dependence.

3. <u>Economic dependence:</u>
The application specifically states "From an economic perspective, the cost for each project is independent from the other, each project is expected to return economic benefits to the facility regardless of whether any other project is completed, and the decision to implement the upgrade at one unit did not have any effect on the outcome of the economic evaluation of the project for the other unit." In addition, the upgrades will be performed during shutdowns that are already scheduled, and will occur regardless of one or both upgrades being completed. Based on this information, it appears the two projects do not appear to share an economic dependence.

4. Conclusion:
Based on the information provided in the application, DAQ agrees that the upgrade projects for Unit 1 and Unit 4 and the change to the limit of fuel sulfur content should each be considered separately for the purposes of NSR aggregation. Note that this determination is only for these specific units, located at this specific facility, and undergoing these specific upgrades.

c. Using projected actual emissions to avoid PSD permitting
As stated above, in order to avoid a PSD review for a modification, the applicant must demonstrate that the modification does not increase emissions of any pollutant above its significance threshold. For each of the Unit 1 and Unit 4 upgrades, CCGF has performed the following calculations: -calculate the baseline actual emissions, calculate the projected actual emissions, and calculate the projected change in emissions.

1. Calculate the baseline for each unit
15A NCAC 02D .0530(b)(1) defines the baseline actual emissions as the average annual emission rate of that pollutant during "…any consecutive 24-month period selected by the owner or operator within the five-year period immediately preceding the date that a complete permit application is received by the Division…" The applications establish a baseline period of January 2018 through December 2019 for Unit 1 and October 2016 through September 2018 for Unit 4:

Table 2: Baseline actual emissions for Unit 1[3]

Pollutant	Baseline Heat Input (annualized)	Emission Rate (lb/mmBtu)	Baseline Actual Emissions (tpy)
NOx	2,412,440	0.0312	37.7
SO_2	2,412,440	0.0006	0.7
CO	2,412,440	0.0231	27.8
VOC	2,412,440	0.0069	8.3
PM_f	2,412,440	0.0019	2.3
PM-10	2,412,440	0.009	10.9
PM-2.5	2,412,440	0.009	10.9

Table 3: Baseline actual emissions for Unit 4

Pollutant	Baseline Heat Input (annualized)	Emission Rate (lb/mmBtu)	Baseline Actual Emissions (tpy)
NOx	2,293,503	0.0331	38.0
SO_2	2,293,503	0.0006	0.7
CO	2,293,503	0.0238	27.3
VOC	2,293,503	0.007	8.1
PM_f	2,293,503	0.002	2.3
PM-10	2,293,503	0.0099	11.4
PM-2.5	2,293,503	0.0099	11.4

CCGF derived the emission factors used in the analysis based on CEMS data, permit limits, and AP-42. See Attachment 1 for the calculations performed by CCGF for the emission factors.

[3] Note that 02D .2609(a) requires that particulate emissions be determined using EPA Methods 5 *and* 202. i.e. "PM" and "particulate matter" is the sum of filterable and condensable particulates.

2. <u>Calculate the projected actual emissions for each unit</u>

CCGF estimated the expected growth in utilization of the facility based on its proprietary dispatching model, which its parent company Southern Power Company uses to predict utilization and make suitable business decisions. CCGF used the dispatching model to analyze the next five years (the design capacity of the units did not increase due to the modification). Based on the dispatching model, the 12-month highest heat input for the two units can be estimated.

Table 4: Projected heat input for Unit 1 and Unit 4

Source	Projected highest 12-month heat input		
	Begin	End	Projected heat input (MMBtu/yr)
Unit 1	December 2024	November 2025	2,571,801
Unit 4	December 2020	November 2021	2,424,813

In the application, CCGF stated that emissions on a lb/MMBtu basis are not expected to change. Therefore, the projected actual emissions can be calculated using the existing emission factors and the projected heat input.

Table 5: Projected Actual Emissions for Unit 1

Pollutant	Projected High Heat Input (12-month period)	Emissions Rate (lbs/mmBtu)	**Projected Actual Emissions (tpy)**
NO_x	2,571,801	0.0312	40.1
SO_2	2,571,801	0.0006	0.8
CO	2,571,801	0.0231	29.7
VOC	2,571,801	0.0069	8.9
PM	2,571,801	0.0019	2.5
PM_{10}	2,571,801	0.009	11.6
$PM_{2.5}$	2,571,801	0.009	11.6

Table 6: Projected Actual Emissions for Unit 4

Pollutant	Projected High Heat Input (12-month period)	Emissions Rate (lbs/mmBtu)	**Projected Actual Emissions (tpy)**
NO_x	2,424,813	0.0331	40.2
SO_2	2,424,813	0.0006	0.7
CO	2,424,813	0.0238	28.9
VOC	2,424,813	0.007	8.5
PM	2,424,813	0.002	2.4
PM_{10}	2,424,813	0.0099	12.1
$PM_{2.5}$	2,424,813	0.0099	12.1

3. Compare the Projected Change in Emissions to the Significance Level

Because emissions on a lb/MMBtu basis are not expected to change (i.e. the emission factors are not expected to change), the projected increase in annual emissions will be solely based on the difference in baseline heat input and projected future heat input.

Table 7: Comparison of Baseline to Projected Actual Emissions for Each Project*

Pollutant	Baseline Emissions (ton/yr)		Projected Actual (ton/yr)		Change in Emissions (ton/yr)		Significant Emission Increase (ton/yr)	SEI Exceeded?
	Unit 1	Unit 4	Unit 1	Unit 4	Unit 1	Unit 4		
NOx	37.70	38.00	40.10	40.20	2.50	2.20	40	No
CO	27.80	27.30	29.70	28.90	1.80	1.60	100	No
PMf	2.30	2.30	2.50	2.40	0.20	0.10	25	No
PM10	10.90	11.40	11.60	12.10	0.70	0.70	15	No
PM2.5	10.90	11.40	11.60	12.10	0.70	0.70	10	No
VOC	8.30	8.10	8.90	8.50	0.60	0.50	40	No
SO_2	0.70	0.70	0.80	0.70	0.10	0.04	40	No

*Numbers may differ from calculated values due to rounding.

As can be seen in Table 7, the projected change in emissions for each project are less than their respective significance levels. Therefore, neither project will trigger a new PSD review.

d. Compliance requirements for use of projected actual emissions:
In order to demonstrate that the projected actual emissions included in the application were accurate, CCGF will monitor emissions from Unit 1 and Unit 4 for five years following the completion of each upgrade. The annual emissions will be compared to the projected emissions. If there is a discrepancy, CCGF may be required to again demonstrate that the upgrade projects did not trigger a PSD review.

The Title V permit will be modified to include two specific conditions (one for each upgrade project) for 15A NCAC 02D .0530(u) "Use of Projected Actual Emissions". The projected annual emissions will be included in the permit for future comparison. Note that this does not constitute an emission limit, and that an exceedance of these projected emissions does not necessarily indicate a violation.

VII. Facility Emissions Review

Due to the upgrade, the maximum heat input capacity of Unit 1 and Unit 4 will each increase by 111 million Btu per hour while firing natural gas and 50 million Btu per hour while firing fuel oil. This increase is not expected to change potential emissions from the facility because Unit 1 and Unit 4 are limited by annual heat input (see Specific Condition 2.2 A.1.d). Actual emissions from this facility on an annual basis are expected to change according to the analysis above.

PSD Increment Tracking for this facility was initially based on facility-wide maximum potential operations of 26,520,000 million Btu per rolling 12-month period. This proposed upgrade will not increase the facility-wide potential operations, so PSD Increment Tracking will not be affected.

See the first page of this review for a summary of actual emissions reported by this facility.
Attachment 1 to this review includes a table of facility-wide NC Toxic Air Pollutants (TAP) after the proposed modifications.

VIII. Other Regulatory Concerns

- A zoning consistency determination was received for these applications on June 2, 2020.
- A PE seal was not required for this permit application.
- The applications were signed by Mr. Jesse English, Plant Manager, as the Responsible Official.
- A specific permit condition for 15A NCAC 02Q .0504 is added to the permit (2.2 C.3.). This condition requires the submittal of an additional Title V permit application within one year of completing these upgrades.

VIII. Recommendations

Issue Permit No. 09881T09.

Attachment 1 to Review of Applications 2300372.20A and .20B
Cleveland County Generating Facility

Baseline and Emission Factor Calculations

The following calculations were performed by CCGF and included in the applications as Attachments A and B

Unit 1:

CEMS Heat input (mmBtu) and NOx (tons)			
Year	Month	NOx tons	Heat Input
2018	January	1.24	29,733
2018	February		
2018	March	0.22	13,724
2018	April	0.23	14,393
2018	May	4.40	280,511
2018	June	5.30	345,250
2018	July	6.48	424,748
2018	August	4.00	263,022
2018	September	4.04	263,706
2018	October	3.23	210,588
2018	November	0.84	51,561
2018	December	1.51	87,477
2019	January	1.02	60,942
2019	February	0.49	30,044
2019	March	1.57	92,652
2019	April	1.93	122,189
2019	May	2.02	130,037
2019	June	5.52	353,137
2019	July	8.45	550,582
2019	August	7.97	529,108
2019	September	7.42	492,732
2019	October	4.95	324,965
2019	November	1.24	75,978
2019	December	1.21	77,802
Annual Average	January 2018 - December 2019	37.7	2,412,440

Cleveland County 1 Emission Factors

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source/Notes:
NOx	0.0312	CEMS - 24-month annual average from Jan. 2018 to Dec. 2019 - (See Appendix A)
SO2	0.0006	CEMS - 24-month annual average Jan. 2018 to Dec. 2019
CO	0.0231	BACT for NG + oil - weighted avg - (See calc. below)
VOC	0.0069	BACT for NG + oil - weighted avg - (See calc. below)
PMf	0.0019	AP-42 gas + oil weighted avg - (See calc. below)
PM10	0.009	Permit limit(s) for NG + oil - weighted avg - (See calc. below)
PM2.5	0.009	Permit limit(s) for NG + oil - weighted avg - (See calc. below)

lb/MMBtu Emission Factor Calculation Backup

Fuel Type	Baseline data (Jan. 2018 to Dec. 2019)		BACT (equiv. lb/mmBtu)		AP42 Table 3.1-2a (lb/mmBtu)	Permit Limit (lb/mmBtu)
	mmBtu	% HI	CO	VOC	PM_filt.	PM10 (PM2.5) f+c
Natural Gas	4,704,658	98.7%	0.022	0.0068	0.0019	0.0083
Oil	61,931	1.3%	0.071	0.014	0.0043	0.0646

lb/mmBtu (BACT equivalent) = ppmvd (BACT Limit)x10^{-6} * MW/385 * F_d * 20.9/(20.9-O_2%, dry)

lb/mmBtu (CO & VOC) = ((BACT equiv. lb/mmBtu gas)*(Baseline mmBtu gas)+(BACT equiv. lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PMf) = ((AP-42 for lb/mmBtu gas)*(Baseline mmBtu gas)+(AP-42 for lb/mmBtu oil) *(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PM10 & 2.5) = ((Permit limit for lb/mmBtu gas)*(Baseline mmBtu gas)+(Permit limit for lb/mmBtu oil)*(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

Example Calculations:

CO lb/mmBtu (BACT Eqiv. NG) = 10 ppmvd * (12+16)/385 * 8710 * 20.9/(20.9-15) = 0.022

CO lb/mmBtu (NG + Oil Weighted avg.) = (0.022*4,704,658 + 0.071*61,931) / (4,704,658 + 61,931) = 0.023

Unit 4:

CEMS Heat input (mmBtu) and NOx (tons)			
Year	Month	NOx tons	Heat Input
2016	October	7.97	537,273
2016	November	3.08	204,940
2016	December	0.82	51,723
2017	January	0.18	4,828
2017	February		
2017	March	1.93	94,931
2017	April	4.09	279,244
2017	May	3.02	204,785
2017	June	3.80	248,150
2017	July	7.74	499,578
2017	August	6.30	413,137
2017	September	4.97	321,741
2017	October	2.76	178,210
2017	November	5.49	352,144
2017	December	0.77	47,882
2018	January	7.86	125,959
2018	February	0.13	8,538
2018	March	0.39	25,530
2018	April	0.52	36,075
2018	May	3.09	207,300
2018	June	3.84	258,617
2018	July	2.45	163,853
2018	August	2.59	175,561
2018	September	2.19	147,007
Annual Average	October 2016 – September 2018	38.0	2,293,503

Cleveland County 4 Emission Factors

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source/Notes:
NOx	0.0331	CEMS - 24-month annual average from Oct. 2016 to Sep. 2018 - (See Appendix A)
SO2	0.0006	CEMS - 24-month annual average Oct. 2016 to Sep. 2018
CO	0.0238	BACT for NG + oil - weighted avg - (See calc. below)
VOC	0.007	BACT for NG + oil - weighted avg - (See calc. below)
PMf	0.002	AP-42 gas + oil weighted avg - (See calc. below)
PM10	0.0099	Permit limit(s) for NG + oil - weighted avg - (See calc. below)
PM2.5	0.0099	Permit limit(s) for NG + oil - weighted avg - (See calc. below)

lb/MMBtu Emission Factor Calculation Backup

Fuel Type	Baseline data (Oct. 2016 to Sep. 2018)		BACT (equiv. lb/mmBtu)		AP-42 Table 3.1-2a (lb/mmBtu)	Permit Limit (lb/mmBtu)
	mmBtu	% HI	CO	VOC	PM_filt.	PM10 (PM2.5) f+c
Natural Gas	4,453,567	97.1%	0.022	0.0068	0.0019	0.0083
Oil	133,438	2.9%	0.071	0.014	0.0043	0.0646

lb/mmBtu (BACT equivalent) = ppmvd (BACT Limit)x10^{-6} * MW/385 * F_d * 20.9/(20.9-O_2%, dry)

lb/mmBtu (CO & VOC) = ((BACT equiv. lb/mmBtu gas)*(Baseline mmBtu gas)+(BACT equiv. lb/mmBtu oil)
*(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PMf) = ((AP-42 for lb/mmBtu gas)*(Baseline mmBtu gas)+(AP-42 for lb/mmBtu oil)
*(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

lb/mmBtu (PM10 & 2.5) = ((Permit limit for lb/mmBtu gas)*(Baseline mmBtu gas)+(Permit limit for lb/mmBtu oil)
*(Baseline mmBtu oil))/(Baseline mmBtu gas + Baseline mmBtu oil)

Example Calculations:

CO lb/mmBtu (BACT Eqiv. NG) = 10 ppmvd * (12+16)/385 * 8710 * 20.9/(20.9-15) = 0.022

CO lb/mmBtu (NG + Oil Weighted avg.) = (0.022*4,453,567 + 0.071*133,438) / (4,453,567 + 133,438) = 0.0238

Toxic Air Pollutants for Facility

Option 1 - Facility with ULN3.0 (Units 1,2,3,&4) - gas only

TOXIC AIR POLLUTANT EMISSIONS INFORMATION FOR THIS SOURCE[5]

TOXIC AIR POLLUTANT	CAS NO.	SOURCE OF EMISSION FACTOR	EXPECTED ACTUAL EMISSIONS AFTER CONTROLS / LIMITATIONS		
			lb/hr	lb/day	lb/yr
1,3 Butadiene		AP-42	NA	NA	1.14E+01
Acetaldehyde		AP-42	3.71E-01	NA	NA
Acrolein		AP-42	5.94E-02	NA	NA
Benzene		AP-42	NA	NA	3.18E+02
Formaldehyde		AP-42	1.70E+00	NA	NA
Toluene		AP-42	1.21E+00	2.90E+01	NA
Xylene		AP-42	5.94E-01	1.43E+01	NA
Sulfuric Acid		Eng. Est.	4.17E+00	1.00E+02	NA

Option 2 - Facility with ULN3.0 (Units 1,2,3,&4) - oil only

TOXIC AIR POLLUTANT EMISSIONS INFORMATION FOR THIS SOURCE[6]

TOXIC AIR POLLUTANT	CAS NO.	SOURCE OF EMISSION FACTOR	EXPECTED ACTUAL EMISSIONS AFTER CONTROLS / LIMITATIONS		
			lb/hr	lb/day	lb/yr
1,3 Butadiene		AP-42	NA	NA	NA
Acetaldehyde		AP-42	0.00E+00	NA	NA
Acrolein		AP-42	0.00E+00	NA	NA
Benzene		AP-42	NA	NA	NA
Formaldehyde		AP-42	2.64E+00	NA	NA
Toluene		AP-42	0.00E+00	0.00E+00	NA
Xylene		AP-42	0.00E+00	0.00E+00	NA
Sulfuric Acid		Eng. Est.	2.03E+00	1.79E+01	NA

Option 3 - Facility with ULN3.0 (Units 1,2,3,&4) - oil/gas combustion

TOXIC AIR POLLUTANT EMISSIONS INFORMATION FOR THIS SOURCE[7]

TOXIC AIR POLLUTANT	CAS NO.	SOURCE OF EMISSION FACTOR	EXPECTED ACTUAL EMISSIONS AFTER CONTROLS / LIMITATIONS		
			lb/hr	lb/day	lb/yr
1,3 Butadiene		AP-42	NA	NA	1.44E+02
Acetaldehyde		AP-42	NA	NA	NA
Acrolein		AP-42	NA	NA	NA
Benzene		AP-42	NA	NA	6.84E+02
Formaldehyde		AP-42	NA	NA	NA
Toluene		AP-42	NA	2.07E+01	NA
Xylene		AP-42	NA	1.02E+01	NA
Sulfuric Acid		Eng. Est.	NA	8.54E+01	NA

Toxic Air Pollutants for Facility with ULN3.0 (Units 1,2,3,&4)- All modes of operation

TOXIC AIR POLLUTANT EMISSIONS INFORMATION FOR THIS SOURCE[8]

TOXIC AIR POLLUTANT	CAS NO.	SOURCE OF EMISSION FACTOR	EXPECTED ACTUAL EMISSIONS AFTER CONTROLS / LIMITATIONS		
			lb/hr	lb/day	lb/yr
1,3 Butadiene		AP-42	NA	NA	1.44E+02
Acetaldehyde		AP-42	3.71E-01	NA	NA
Acrolein		AP-42	5.94E-02	NA	NA
Benzene		AP-42	NA	NA	6.84E+02
Formaldehyde		AP-42	2.64E+00	NA	NA
Toluene		AP-42	1.21E+00	2.90E+01	NA
Xylene		AP-42	5.94E-01	1.43E+01	NA
Sulfuric Acid		Eng. Est.	4.17E+00	1.00E+02	NA

[5] Emissions in this table reflect facility wide natural gas operations. Annual emissions are based on the facility heat input limit (26,520,000 mmBtu/yr).

[6] Emissions in this table reflect facility wide fuel oil operations. Daily emissions are based on the facility oil operating limit (76,644 mmBtu/24-hr block).

[7] Emissions in this table reflect oil and gas operations for the facility. Daily emissions for each turbine are based on one quarter of the facility oil operating limit(59,612 mmBtu total per/24-hr block) and the remainder of the day gas combustion. Annual emissions (lb/yr) are based on the facility heat input limit (26,520,000 mmBtu/yr) and facility oil heat input limit (8,516,000 mmBtu/yr).

[8] Emissions in this table reflect facility worst case (maximum) from Options 1-3