PUBLIC NOTICE

Tennessee Valley Authority (TVA) John Sevier Combined Cycle Plant has applied to the Tennessee Department of Environment and Conservation, Division of Air Pollution Control for a significant modification to an existing major source operating permit subject to the provisions of paragraph 1200-03-09-.02(11) of the Tennessee Air Pollution Control Regulations. A major source operating permit is required by both the Federal Clean Air Act and the Tennessee Air Pollution Control Regulations. They seek to obtain a significant modification to a major source operating permit for Title I modifications (40 CFR 63 Subparts DDDDD and JJJJJJ) and changes to allowable emission limits and monitoring requirements at their electric utility. The existing Title V operating permit subject to the modification is identified as follows: Division identification number 37-0007/567175. The emission sources affected by the modification are identified as follows: 37-0007-00, 37-0007-15, 37-0007-16. This significant modification is conducted pursuant to subpart 1200-03-09-.02(11)(f)5(iv) of the Tennessee Air Pollution Control Regulations. Only the portion of the Title V permit affected by the significant modification is open to comment during the notice period.

EPA has agreed to treat this draft Part 70 permit as a proposed Part 70 permit and to perform its 45-day review provided by the law concurrently with the public notice period. If any substantive comments are received, EPA's 45-day review period will cease to be performed concurrently with the public notice period. EPA's 45-day review period will start once the public notice period has been completed and EPA receives notification from the Tennessee Air Pollution Control Division that comments have been received and resolved. Whether EPA's 45-day review period is performed concurrently with the public comment period or after the public comment period has ended, the deadline for citizen's petitions to the EPA Administrator will be determined as if EPA's 45-day review period is performed after the public comment period has ended (*i.e.*, sequentially). The status regarding EPA's 45-day review of these permits and the deadline for submitting a citizen's petition can be found at the following website address:

http://www2.epa.gov/caa-permitting/caa-permitting-epas-southeastern-region

Copies of the application materials and draft permits are available for public inspection during normal business hours at the following locations:

H. B. Stamps Memorial Library 407 East Main Street, Suite 1 Rogersville, TN 37857	and	Tennessee Department of Environment and Conservation Division of Air Pollution Control William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, TN 37243

Electronic copies of the draft permits are available by accessing the TDEC internet site located at:

http://www.tn.gov/environment/topic/ppo-air

Questions concerning the source(s) may be addressed to Mr. Travis Blake at (615) 532-0617 or by e-mail at travis.blake@tn.gov.

Interested parties are invited to review these materials and comment. In addition, a public hearing may be requested at which written or oral presentations may be made. To be considered, written comments or requests for a public hearing must be received no later than 4:30 PM on October 31, 2016. To assure that written comments are received and addressed in a timely manner, written comments must be submitted using one of the following methods:

1. **Mail, private carrier, or hand delivery:** Address written comments to Travis Blake, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 15th Floor, Nashville, Tennessee 37243.

2. **E-mail**: Submit electronic comments to air.pollution.control@tn.gov.

A final determination will be made after weighing all relevant comments.

Individuals with disabilities who wish to review information maintained at the above-mentioned depositories should contact the Tennessee Department of Environment and Conservation to discuss any auxiliary aids or services needed to facilitate such review. Such contact may be in person, by writing, telephone, or other means, and should be made no less than ten days prior to the end of the public comment period to allow time to provide such aid or services. Contact the Tennessee Department of Environment and Conservation ADA Coordinator, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 2nd Floor, Nashville, TN 37243, 1-(866)-253-5827. Hearing impaired callers may use the Tennessee Relay Service, 1-(800)-848-0298.

For the "Rogersville Review" -- publish once during the time period of September 26, 2016, through September 30, 2016.

Air Pollution Control DATE: SEPTEMBER 12, 2016
Assigned to –Travis Blake

No alterations to the above are allowed:
TVA must pay to place this advertisement in the newspaper
Air Pollution Control must be furnished with an affidavit from the newspaper stating that the ad was run and the date of the ad or one complete sheet from the newspaper showing this advertisement, the name of the newspaper and the date of publication. Mail to Travis Blake, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 15th Floor, Nashville, Tennessee 37243.

TENNESSEE AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243-1531

SIGNIFICANT MODIFICATION #1 TO
OPERATING PERMIT (TITLE V) Issued Pursuant to Tennessee Air Quality Act

This permit fulfills the requirements of Title V of the Federal Clean Air Act (42 U.S.C. 7661a-7661e) and the federal regulations promulgated thereunder at 40 CFR Part 70. (FR Vol. 57, No. 140, Tuesday, July 21, 1992 p.32295-32312). This permit is issued in accordance with the provisions of paragraph 1200-03-09-.02(11) of the Tennessee Air Pollution Control Regulations. The permittee has been granted permission to operate an air contaminant source in accordance with emissions limitations and monitoring requirements set forth herein.

Issue Date: **April 29, 2014**

Modification Date: ********DRAFT********

Expiration Date: **April 28, 2019**

Permit Number:
567175

Issued To:
Tennessee Valley Authority
John Sevier Combined Cycle Plant

Installation Address:
299 TVA Pond Road
Rogersville

Installation Description: **Electric Power Generating Facility**

14: Combined/Simple-Cycle Turbines
15: Natural Gas Fired Auxiliary Boiler
16: Two Natural Gas Fired Heaters
17: Mechanical-Draft Cooling Tower
18: Emergency Fire Pump
19: Two Distillate Oil Storage Tanks

Emission Source Reference No.: 37-0007

Renewal Application Due Date:
Between August 1, 2018, and October 30, 2018

Primary SIC: 49

Information Relied Upon:
Application dated April 22, 2013. Significant Modification #1 application dated March 2, 2016.

(continued on the next page)

____
TECHNICAL SECRETARY

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

POST AT INSTALLATION ADDRESS

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SECTION A
GENERAL PERMIT CONDITIONS

A permit issued under the provisions of paragraph 1200-03-09-.02(11) is a permit issued pursuant to the requirements of Title V of the Federal Act and its implementing Federal regulations promulgated at 40 CFR, Part 70.

A1. **Definitions.** Terms not otherwise defined in the permit shall have the meaning assigned to such terms in the referenced regulation.

TAPCR 1200-03

A2. **Compliance requirement.** All terms and conditions in a permit issued pursuant to paragraph 1200-03-09-.02(11) including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Federal Act.

The permittee shall comply with all conditions of its permit. Except for requirements specifically designated herein as not being federally enforceable (State Only), non-compliance with the permit requirements is a violation of the Federal Act and the Tennessee Air Quality Act and is grounds for enforcement action; for a permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Non-compliance with permit conditions specifically designated herein as not being federally enforceable (State Only) is a violation of the Tennessee Air Quality Act and may be grounds for these actions.

TAPCR 1200-03-09-.02(11)(e)2(i) and 1200-03-09-.02(11)(e)1(vi)(I)

A3. **Need to halt or reduce activity.** The need to halt or reduce activity is not a defense for noncompliance. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this item shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations.

TAPCR 1200-03-09-.02(11)(e)1(vi)(II)

A4. **The permit.** The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

TAPCR 1200-03-09-.02(11)(e)1(vi)(III)

A5. **Property rights.** The permit does not convey any property rights of any sort, or any exclusive privilege.

TAPCR 1200-03-09-.02(11)(e)1(vi)(IV)

A6. **Submittal of requested information.** The permittee shall furnish to the Technical Secretary, within a reasonable time, any information that the Technical Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or termination of the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Technical Secretary copies of records required to be kept by the permit. If the permittee claims that such information is confidential, the Technical Secretary may review that claim and hold the information in protected status until such time that the Board can hear any contested proceedings regarding confidentiality disputes. If the information is desired by EPA, the permittee may mail the information directly to EPA. Any claims of confidentiality for federal purposes will be determined by EPA.

TAPCR 1200-03-09-.02(11)(e)1(vi)(V)

A7. **Severability clause.** The requirements of this permit are severable. A dispute regarding one or more requirements of this permit does not invalidate or otherwise excuse the permittee from their duty to comply with the remaining portion of the permit.

TAPCR 1200-03-09.02(11)(e)1(v)

A8. **Fee payment.**

(a) The permittee shall pay an annual major source emission fee based upon the responsible official's choice of actual emissions or allowable emissions. An emission cap of 4,000 tons per year per regulated pollutant per major source SIC Code shall apply to actual or allowable based emission fees. A major source annual emission fee will not be charged for emissions in excess of the cap (s) or for carbon monoxide.

(b) Major sources who have filed a timely, complete operating permit application in accordance with 1200-03-09-.02(11), shall pay allowable emission based fees until the beginning of the next annual accounting period following receipt of their major source operating permit. At that time, the permittee shall begin paying their annual emission fee based upon their choice of actual or allowable based fees, or mixed actual and allowable based fees as stated under SECTION E of this permit. Once permitted, altering the existing choice shall be accomplished by a written request of the major source, filed in the office of the Technical Secretary at least one hundred eighty days prior to the expiration or reissuance of the major source operating permit.

(c) Major sources must conform to the following requirements with respect to fee payments:

1. If a major source choosing an allowable based annual emission fee wishes to restructure its allowable emissions for the purposes of lowering its annual emission fees, a mutually agreed upon, more restrictive regulatory requirement may be established to minimize the allowable emissions and thus the annual emission fee. The more restrictive requirement must be specified on the permit, and must include the method used to determine compliance with the limitation. The documentation procedure to be followed by the major source must also be included to insure that the limit is not exceeded. Restructuring the allowable emissions is permissible only in the annual accounting periods of eligibility and only, if the written request for restructuring is filed with the Technical Secretary at least 120 days prior to the beginning of the annual accounting period of eligibility. These periods of eligibility occur upon expiration of the initial major source operating permit, renewal of an expired major source operating permit or reissuance of a major source operating permit.

2. Major sources paying on allowable based emission fees will be billed by the Division no later than April 1 prior to the end of the accounting period. The major source annual emission fee is due July 1 following the end of the accounting period.

3. Major sources choosing an actual based annual emission fee shall file an actual emissions analysis with the Technical Secretary which summarizes the actual emissions of all regulated pollutants at the air contaminant sources of their facility. Based upon the actual emissions analysis, the source shall calculate the fee due and submit the payment and the analysis each July 1st following the end of the annual accounting period.

4. Major sources choosing a mixture of allowable and actual based emission fees shall file an actual emissions and allowable emissions analysis with the Technical Secretary which summarizes the actual and allowable emissions of all regulated pollutants at the air contaminant sources of their facility. Based upon the analysis, the source shall calculate the fee due and submit the payment and the analysis each July 1st following the end of the annual accounting period.

The mixed based fee shall be calculated utilizing the 4,000 ton cap specified in subparagraph 1200-03-26-.02(2)(i). In determining the tonnages to be applied toward the regulated pollutant 4,000 ton cap in a mixed based fee, the source shall first calculate the actual emission based fees for a regulated pollutant and apply that tonnage toward the regulated pollutant's cap. The remaining tonnage available in the 4,000 ton category of a regulated pollutant shall be subject to allowable emission based fee calculations for the sources that were not included in the actual emission based fee calculations. Once the 4,000 ton cap has been reached for a regulated pollutant, no additional fee shall be required.

5. Major sources choosing to pay their major source annual emission fee based on actual based emissions or a mixture of allowable and actual based emissions may request an extension of time to file their emissions analysis with the Technical Secretary. The extension may be granted by the Technical Secretary up to ninety

(90) days. The request for extension must be postmarked no later than July 1 or the request for extension shall be denied. The request for extension to file must state the reason and give an adequate explanation.

An estimated annual emission fee payment of no less than eighty percent (80%) of the fee due July 1 must accompany the request for extension to avoid penalties and interest on the underpayment of the annual emission fee. A remaining balance due must accompany the emission analysis. If there has been an overpayment, a refund may be requested in writing to the Division or be applied as a credit toward next year's major source annual emission fee. The request for extension of time is not available to major sources choosing to pay their major source annual emission fee based on allowable emissions.

6. Newly constructed major sources or minor existing sources modifying their operations such that they become a major source in the midst of the standard July 1st to June 30th annual accounting period, shall pay allowable based annual emission fees for the fractional remainder of the annual accounting period commencing upon their start-up. At the beginning of the next annual accounting period, the "responsible official" of the source may choose to pay annual emission fees based on actual or allowable emissions or a mixture of the two as provided for in this rule 1200-03-26-.02.

(d) Where more than one (1) allowable emission limit is applicable to a regulated pollutant, the allowable emissions for the regulated pollutants shall not be double counted. Major sources subject to the provisions of paragraph 1200-03-26-.02(9) shall apportion their emissions as follows to ensure that their fees are not double counted.

1. Sources that are subject to federally promulgated hazardous air pollutant standards that can be imposed under Chapter 1200-03-11 or Chapter 1200-03-31 will place such regulated emissions in the specific hazardous air pollutant under regulation. If the pollutant is also in the family of volatile organic compounds or the family of particulates, the pollutant shall not be placed in that respective family category.

2. A miscellaneous category of hazardous air pollutants shall be used for hazardous air pollutants listed at part 1200-03-26-.02(2)(i)12 that do not have an allowable emission standard. A pollutant placed in this category shall not be subject to being placed in any other category such as volatile organic compounds or particulates.

3. Each individual hazardous air pollutant and the miscellaneous category of hazardous air pollutants is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i).

4. Major sources that wish to pay annual emission fees for PM_{10} on an allowable emission basis may do so if they have a specific PM_{10} allowable emission standard. If a major source has a total particulate emission standard, but wishes to pay annual emission fees on an actual PM_{10} emission basis, it may do so if the PM_{10} actual emission levels are proven to the satisfaction of the Technical Secretary. The method to demonstrate the actual PM_{10} emission levels must be made as part of the source's major source operating permit in advance in order to exercise this option. The PM_{10} emissions reported under these options shall not be subject to fees under the family of particulate emissions. The 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i) shall also apply to PM_{10} emissions.

TAPCR 1200-03-26-.02 (3) and (9) and 1200-03-09-.02(11)(e)1(vii)

A9. **<u>Permit revision not required.</u>** A permit revision will not be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or process for changes that are provided for in the permit.

TAPCR 1200-03-09-.02(11)(e)1(viii)

A10. **<u>Inspection and entry.</u>** Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Technical Secretary or his authorized representative to perform the following for the purposes of determining compliance with the permit applicable requirements:

(a) Enter upon, at reasonable times, the permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

(d) As authorized by the Clean Air Act and Chapter 1200-03-10 of TAPCR, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(e) "Reasonable times" shall be considered to be customary business hours unless reasonable cause exists to suspect noncompliance with the Act, Division 1200-03 or any permit issued pursuant thereto and the Technical Secretary specifically authorizes an inspector to inspect a facility at any other time.

TAPCR 1200-03-09-.02(11)(e)3.(ii)

A11. <u>Permit shield.</u>

(a) Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements as of the date of permit issuance, provided that:

1. Such applicable requirements are included and are specifically identified in the permit; or

2. The Technical Secretary, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

(b) Nothing in this permit shall alter or affect the following:

1. The provisions of section 303 of the Federal Act (emergency orders), including the authority of the Administrator under that section. Similarly, the provisions of T.C.A. §68-201-109 (emergency orders) including the authority of the Governor under the section;

2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

3. The applicable requirements of the acid rain program, consistent with section 408(a) of the Federal Act; or

4. The ability of EPA to obtain information from a source pursuant to section 114 of the Federal Act.

(c) Permit shield is granted to the permittee.

TAPCR 1200-03-09-.02(11)(e)6

A12 (SM1). <u>Permit renewal and expiration.</u>

(a) An application for permit renewal must be submitted at least 180 days, but no more than 270 days prior to the expiration of this permit. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted.

(b) Provided that the permittee submits a timely and complete application for permit renewal the source will not be considered in violation of paragraph 1200-03-09-.02(11) until the Technical Secretary takes final action on the permit application, except as otherwise noted in paragraph 1200-03-09-.02(11).

(c) This permit, its shield provided in Condition A11, and its conditions will be extended and effective after its expiration date provided that the source has submitted a timely, complete renewal application to the Technical Secretary.

TAPCR 1200-03-09-.02(11)(f)3 and 2, 1200-03-09-.02(11)(d)1(i)(III), and 1200-03-09-.02(11)(a)2

A13. <u>Reopening for cause.</u>

(a) A permit shall be reopened and revised prior to the expiration of the permit under any of the circumstances listed below:

1. Additional applicable requirements under the Federal Act become applicable to the sources contained in this permit provided the permit has a remaining term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the permit expiration date of this permit, unless the original has been extended pursuant to 1200-03-09-.02(11)(a)2.

2. Additional requirements become applicable to an affected source under the acid rain program.

3. The Technical Secretary or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

4. The Technical Secretary or EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(b) Proceedings to reopen and issue a permit shall follow the same proceedings as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists, and not the entire permit. Such reopening shall be made as expeditiously as practicable.

(c) Reopenings for cause shall not be initiated before a notice of such intent is provided to the permittee by the Technical Secretary at least 30 days in advance of the date that the permit is to be reopened except that the Technical Secretary may provide a shorter time period in the case of an emergency. An emergency shall be established by the criteria of T.C.A. 68-201-109 or other compelling reasons that public welfare is being adversely affected by the operation of a source that is in compliance with its permit requirements.

(d) If the Administrator finds that cause exists to terminate, modify, or revoke and reissue a permit as identified in A13, he is required under federal rules to notify the Technical Secretary and the permittee of such findings in writing. Upon receipt of such notification, the Technical Secretary shall investigate the matter in order to determine if he agrees or disagrees with the Administrator's findings. If he agrees with the Administrator's findings, the Technical Secretary shall conduct the reopening in the following manner:

1. The Technical Secretary shall, within 90 days after receipt of such notification, forward to EPA a proposed determination of termination, modification, or revocation and reissuance, as appropriate. If the Administrator grants additional time to secure permit applications or additional information from the permittee, the Technical Secretary shall have the additional time period added to the standard 90 day time period.

2. EPA will evaluate the Technical Secretary's proposed revisions and respond as to their evaluation.

3. If EPA agrees with the proposed revisions, the Technical Secretary shall proceed with the reopening in the same manner prescribed under Condition A13 (b) and Condition A13 (c).

4. If the Technical Secretary disagrees with either the findings or the Administrator that a permit should be reopened or an objection of the Administrator to a proposed revision to a permit submitted pursuant to Condition A13(d), he shall bring the matter to the Board at its next regularly scheduled meeting for instructions as to how he should proceed. The permittee shall be required to file a written brief expressing their position relative to the Administrator's objection and have a responsible official present at the meeting to answer questions for the Board. If the Board agrees that EPA is wrong in their demand for a permit revision, they shall instruct the Technical Secretary to conform to EPA's demand, but to issue the permit under protest preserving all rights available for litigation against EPA.

TAPCR 1200-03-09-.02(11)(f)6 and 7.

A14. <u>**Permit transference.**</u> An administrative permit amendment allows for a change of ownership or operational control of a source where the Technical Secretary determines that no other change in the permit is necessary, provided that the following requirements are met:

(a) Transfer of ownership permit application is filed consistent with the provisions of 1200-03-09-.03(6), and

(b) written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Technical Secretary.

TAPCR 1200-03-09-.02(11)(f)4(i)(IV) and 1200-03-09-.03(6)

A15. **Air pollution alert.** When the Technical Secretary has declared that an air pollution alert, an air pollution warning, or an air pollution emergency exists, the permittee must follow the requirements for that episode level as outlined in TAPCR 1200-03-09-.03(1) and TAPCR 1200-03-15-.03.

A16. **Construction permit required.** Except as exempted in TAPCR 1200-03-09-.04, or excluded in subparagraph TAPCR 1200-03-02-.01(1)(aa) or subparagraph TAPCR 1200-03-02-.01(1)(cc), this facility shall not begin the construction of a new air contaminant source or the modification of an air contaminant source which may result in the discharge of air contaminants without first having applied for and received from the Technical Secretary a construction permit for the construction or modification of such air contaminant source.

TAPCR 1200-03-09-.01(1)(a)

A17. **Notification of changes.** The permittee shall notify the Technical Secretary 30 days prior to commencement of any of the following changes to an air contaminant source which would not be a modification requiring a construction permit.

(a) change in air pollution control equipment

(b) change in stack height or diameter

(c) change in exit velocity of more than 25 percent or exit temperature of more than 15 percent based on absolute temperature.

TAPCR 1200-03-09-.02(7)

A18. **Schedule of compliance.** The permittee will comply with any applicable requirement that becomes effective during the permit term on a timely basis. If the permittee is not in compliance the permittee must submit a schedule for coming into compliance which must include a schedule of remedial measure(s), including an enforceable set of deadlines for specific actions.

TAPCR 1200-03-09-.02(11)(d)3 and 40 CFR §70.5(c)

A19. **Title VI.**

(a) The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR, Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to Section 82.156.

2. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to Section 82.158.

3. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to Section 82.161.

(b) If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR, Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

(c) The permittee shall be allowed to switch from any ozone-depleting substance to any alternative that is listed in the Significant New Alternatives Program(SNAP) promulgated pursuant to 40 CFR, Part 82, Subpart G, Significant New Alternatives Policy Program.

A20. **112 (r).** The permittee shall comply with the requirement to submit to the Administrator or designated State Agency a risk management plan, including a registration that reflects all covered processes, by June 21, 1999, if the permittee's facility is required pursuant to 40 CFR, 68, to submit such a plan.

A21. **Acid rain program**

(**a**) The permittee shall not produce emissions in excess of allowances held under Title IV of the Federal Clean Air Act and the regulations promulgated thereunder and TAPCR 1200-03-30.

(**b**) The permittee shall not be subject to the permit revision requirements of TAPCR 1200-03-09-.02(11)(f) for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit revision under any other applicable requirement.

(**c**) Where an applicable requirement of the Federal Act is more stringent than the Federal regulations promulgated under Title IV of the Federal Act, both provisions shall be incorporated into the permit and shall be enforceable by the administrator.

(**d**) No limit shall be placed on the number of allowances held by this source under the acid rain program. The permittee may not use allowances as a defense for noncompliance with any other applicable requirement.

(**e**) Any allowance shall be accounted for according to the regulations promulgated under Title IV of the Federal Clean Air Act and the provisions of TAPCR 1200-03-30.

TAPCR 1200-03-09-.02(11)(e)1(iv)

SECTION B

GENERAL CONDITIONS for MONITORING, REPORTING, and ENFORCEMENT

B1. **Recordkeeping.** Monitoring and related record keeping shall be performed in accordance with the requirements specified in the permit conditions for each individual permit unit. In no case shall reports of any required monitoring and record keeping be submitted less frequently than every six months.

(a) Where applicable, records of required monitoring information include the following:

1. The date, place as defined in the permit, and time of sampling or measurements;
2. The date(s) analyses were performed;
3. The company or entity that performed the analysis;
4. The analytical techniques or methods used;
5. The results of such analyses; and
6. The operating conditions as existing at the time of sampling or measurement.

(b) Digital data accumulation which utilizes valid data compression techniques shall be acceptable for compliance determination as long as such compression does not violate an applicable requirement and its use has been approved in advance by the Technical Secretary.

TAPCR 1200-03-09-.02(11)(e)1(iii)

B2. **Retention of monitoring data.** The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

TAPCR 1200-03-09-.02(11)(e)1(iii)(II)II

B3. **Reporting.** Reports of any required monitoring and record keeping shall be submitted to the Technical Secretary in accordance with the frequencies specified in the permit conditions for each individual permit unit. Reports shall be submitted within 60 days of the close of the reporting period unless otherwise noted. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official. Reports required under "State only requirements" are not required to be certified by a responsible official.

TAPCR 1200-03-09-.02(11)(e)1(iii)

B4. **Certification.** Except for reports required under "State Only" requirements, any application form, report or compliance certification submitted pursuant to the requirements of this permit shall contain certification by a responsible official of truth, accuracy and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

TAPCR 1200-03-09-.02(11)(d)4

B5 (SM1). **Annual compliance certification.** The permittee shall submit annually compliance certifications with terms and conditions contained in Sections A, B, D and E of this permit, including emission limitations, standards, or work practices. This compliance certification shall include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

(a) The identification of each term or condition of the permit that is the basis of the certification;

(b) The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required by this permit If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Act, which prohibits knowingly making a false certification or omitting material information;

(c) Reserved.

(d) The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in B5(b) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion* or exceedance** as defined below occurred; and

(e) Such other facts as the Technical Secretary may require to determine the compliance status of the source.

* "Excursion" shall mean a departure from an indicator range established for monitoring under this paragraph, consistent with any averaging period specified for averaging the results of the monitoring.

** "Exceedance" shall mean 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 (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

40 CFR Part 70.6(c)(5)(iii) as amended in the Federal Register Vol.79, No. 144, July 28, 2014, pages 43661 through 43667

B6. **<u>Submission of compliance certification.</u>** The compliance certification shall be submitted to:

Technical Secretary Division of Air Pollution Control Johnson City Environmental Field Office 2305 Silverdale Road Johnson City, TN 37601-2162 e-mail: APC.JCEFO@tn.gov	and	Air and EPCRA Enforcement Branch US EPA Region IV 61 Forsyth Street, SW Atlanta, Georgia 30303

TAPCR 1200-03-09-.02(11)(e)3(v)(IV)

B7. **<u>Emergency provisions.</u>** An emergency constitutes an affirmative defense to an enforcement action brought against this source for noncompliance with a technology based emission limitation due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

(a) The affirmative defense of the emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An emergency occurred and that the permittee can identify the probable cause(s) of the emergency. "Probable" must be supported by a credible investigation into the incident that seeks to identify the causes and results in an explanation supported by generally accepted engineering or scientific principles.

2. The permitted source was at the time being properly operated. In determining whether or not a source was being properly operated, the Technical Secretary shall examine the source's written standard operating procedures which were in effect at the time of the noncompliance and any other code as detailed below that would be relevant to preventing the noncompliance. Adherence to the source's standard operating procedures will be the test of adequate preventative maintenance, careless operation, improper operation or operator error to the extent that such adherence would prevent noncompliance. The source's failure to follow recognized standards of practice to the extent that adherence to such a standard would have prevented noncompliance will disqualify the source from any claim of an emergency and an affirmative defense.

3. During the period of the emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit.

4. The permittee submitted notice of the emergency to the Technical Secretary according to the notification criteria for malfunctions in rule 1200-03-20-.03. For the purposes of this condition, "emergency" shall be substituted for "malfunction(s)" in rule 1200-03-20-.03 to determine the relevant notification threshold. The notice shall include a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(b) In any enforcement proceeding the permittee seeking to establish the occurrence of an emergency has the burden of proof.

(c) The provisions of this condition are in addition to any emergency, malfunction or upset requirement contained in Division 1200-03 or other applicable requirement.

TAPCR 1200-03-09-.02(11)(e)7

B8. **Excess emissions reporting.**

(a) The permittee shall promptly notify the Technical Secretary when any emission source, air pollution control equipment, or related facility breaks down in such a manner to cause the emission of air contaminants in excess of the applicable emission standards contained in Division 1200-03 or any permit issued thereto, or of sufficient duration to cause damage to property or public health. The permittee must provide the Technical Secretary with a statement giving all pertinent facts, including the estimated duration of the breakdown. Violations of the visible emission standard which occur for less than 20 minutes in one day (midnight to midnight) need not be reported. Prompt notification will be within 24 hours of the malfunction and shall be provided by telephone to the Division's Nashville office. The Technical Secretary shall be notified when the condition causing the failure or breakdown has been corrected. In attainment and unclassified areas if emissions other than from sources designated as significantly impacting on a nonattainment area in excess of the standards will not and do not occur over more than a 24-hour period (or will not recur over more than a 24-hour period) and no damage to property and or public health is anticipated, notification is not required.

(b) Any malfunction that creates an imminent hazard to health must be reported by telephone immediately to the Division's Nashville office at (615) 532-0554 and to the State Civil Defense.

(c) A log of all malfunctions, startups, and shutdowns resulting in emissions in excess of the standards in Division 1200-03 or any permit issued thereto must be kept at the plant. All information shall be entered in the log no later than twenty-four (24) hours after the startup or shutdown is complete, or the malfunction has ceased or has been corrected. Any later discovered corrections can be added in the log as footnotes with the reason given for the change. This log must record at least the following:

1. Stack or emission point involved
2. Time malfunction, startup, or shutdown began and/or when first noticed
3. Type of malfunction and/or reason for shutdown
4. Time startup or shutdown was complete or time the air contaminant source returned to normal operation
5. The company employee making entry on the log must sign, date, and indicate the time of each log entry

The information under items 1. and 2. must be entered into the log by the end of the shift during which the malfunction or startup began. For any source utilizing continuous emission(s) monitoring, continuous emission(s) monitoring collection satisfies the above log keeping requirement.

TAPCR 1200-03-20-.03 and .04

B9. **Malfunctions, startups and shutdowns - reasonable measures required.** The permittee must take all reasonable measures to keep emissions to a minimum during startups, shutdowns, and malfunctions. These measures may include installation and use of alternate control systems, changes in operating methods or procedures, cessation of operation until the process equipment and/or air pollution control equipment is repaired, maintaining sufficient spare parts, use of overtime labor, use of outside consultants and contractors, and other appropriate means. Failures that are caused by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions. This provision does not apply to standards found in 40 CFR, Parts 60(Standards of performance for new stationary sources), 61(National emission standards for hazardous air pollutants) and 63(National emission standards for hazardous air pollutants for source categories). TAPCR 1200-03-20-.02

B10. **Report required upon the issuance of a notice of violation for excess emissions.** The permittee must submit within twenty (20) days after receipt of the notice of violation, the data shown below to assist the Technical Secretary in deciding whether to excuse or validate the violation. If this data has previously been available to the Technical Secretary prior to the issuance of the notice of violation no further action is required of the violating source. However, if the source desires to submit additional information, then this must be submitted within the same twenty (20) day time period. The minimum data requirements are:

(a) The identity of the stack and/or other emission point where the excess emission(s) occurred;

(b) The magnitude of the excess emissions expressed in pounds per hour and the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions;

(c) The time and duration of the emissions;

(d) The nature and cause of such emissions;

(e) For malfunctions, the steps taken to correct the situation and the action taken or planned to prevent the recurrence of such malfunctions;

(f) The steps taken to limit the excess emissions during the occurrence reported, and

(g) If applicable, documentation that the air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good operating practices for minimizing emissions.

Failure to submit the required report within the twenty (20) day period specified shall preclude the admissibility of the data for consideration of excusal for malfunctions.

TAPCR 1200-03-20-.06(2), (3) and (4)

SECTION C
PERMIT CHANGES

C1. **Operational flexibility changes.** The source may make operational flexibility changes that are not addressed or prohibited by the permit without a permit revision subject to the following requirements:

(a) The change cannot be subject to a requirement of Title IV of the Federal Act or Chapter 1200-03-30.

(b) The change cannot be a modification under any provision of Title I of the federal Act or Division 1200-03.

(c) Each change shall meet all applicable requirements and shall not violate any existing permit term or condition.

(d) The source must provide contemporaneous written notice to the Technical Secretary and EPA of each such change, except for changes that are below the threshold of levels that are specified in Rule 1200-03-09-.04.

(e) Each change shall be described in the notice including the date, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change.

(f) The change shall not qualify for a permit shield under the provisions of part 1200-03-09-.02(11)(e)6.

(g) The permittee shall keep a record describing the changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes. The records shall be retained until the changes are incorporated into subsequently issued permits.

TAPCR 1200-03-09-.02(11)(a)4 (ii)

C2. **Section 502(b)(10) changes.**

(a) The permittee can make certain changes without requiring a permit revision, if the changes are not modifications under Title I of the Federal Act or Division 1200-03 and the changes do not exceed the emissions allowable under the permit. The permittee must, however, provide the Administrator and Technical Secretary with written notification within a minimum of 7 days in advance of the proposed changes. The Technical Secretary may waive the 7 day advance notice in instances where the source demonstrates in writing that an emergency necessitates the change. Emergency shall be demonstrated by the criteria of TAPCR 1200-03-09-.02(11)(e)7 and in no way shall it include changes solely to take advantages of an unforeseen business opportunity. The Technical Secretary and EPA shall attach each such notice to their copy of the relevant permit.

(b) The written notification must be signed by a facility Title V responsible official and include the following:

1. a brief description of the change within the permitted facility;
2. the date on which the change will occur;
3. a declaration and quantification of any change in emissions;
4. a declaration of any permit term or condition that is no longer applicable as a result of the change; and
5. a declaration that the requested change is not a Title I modification and will not exceed allowable emissions under the permit.

(c) The permit shield provisions of TAPCR 1200-03-09-.02(11)(e)6 shall not apply to Section 502(b)(10) changes.

TAPCR 1200-03-09-.02(11)(a)4 (i)

C3. **Administrative amendment.**

(a) Administrative permit amendments to this permit shall be in accordance with 1200-03-09-.02(11)(f)4. The source may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

(b) The permit shield shall be extended as part of an administrative permit amendment revision consistent with the provisions of TAPCR 1200-03-09-.02(11)(e)6 for such revisions made pursuant to item (c) of this condition which meet the relevant requirements of TAPCR 1200-03-09-.02(11)(e), TAPCR 1200-03-09-.02(11)(f) and TAPCR 1200-03-09-.02(11)(g) for significant permit modifications.

(c) Proceedings to review and grant administrative permit amendments shall be limited to only those parts of the permit for which cause to amend exists, and not the entire permit.

TAPCR 1200-03-09-.02(11)(f)4

C4. **Minor permit modifications.**

(a) The permittee may submit an application for a minor permit modification in accordance with TAPCR 1200-03-09-.02(11)(f)5(ii).

(b) The permittee may make the change proposed in its minor permit modification immediately after an application is filed with the Technical Secretary.

(c) Proceedings to review and modify permits shall be limited to only those parts of the permit for which cause to modify exists, and not the entire permit.

(d) Minor permit modifications do not qualify for a permit shield.

TAPCR 1200-03-09-.02(11)(f)5(ii)

C5. **Significant permit modifications.**

(a) The permittee may submit an application for a significant modification in accordance with TAPCR 1200-03-09-.02(11)(f)5(iv).

(b) Proceedings to review and modify permits shall be limited to only those parts of the permit for which cause to modify exists, and not the entire permit.

TAPCR 1200-03-09-.02(11)(f)5(iv)

C6. **New construction or modifications.** Future construction at this facility that is subject to the provisions of TAPCR 1200-03-09-.01 shall be governed by the following:

(a) The permittee shall designate in their construction permit application the route that they desire to follow for the purposes of incorporating the newly constructed or modified sources into their existing operating permit. The Technical Secretary shall use that information to prepare the operating permit application submittal deadlines in their construction permit.

(b) Sources desiring the permit shield shall choose the administrative amendment route of TAPCR 1200-03-09-.02(11)(f)4 or the significant modification route of TAPCR 1200-03-09-.02(11)(f)5(iv).

(c) Sources desiring expediency instead of the permit shield shall choose the minor permit modification procedure route of TAPCR 1200-03-09-.02(11)(f)5(ii) or group processing of minor modifications under the provisions of TAPCR 1200-03-09-.02(11)(f)5(iii) as applicable to the magnitude of their construction.

TAPCR 1200-03-09-.02(11)(d) 1(i)(V)

SECTION D

GENERAL APPLICABLE REQUIREMENTS

D1. **Visible emissions.** With the exception of air emission sources exempt from the requirements of TAPCR Chapter 1200-03-05 and air emission sources for which a different opacity standard is specifically provided elsewhere in this permit, the permittee shall not cause, suffer, allow or permit discharge of a visible emission from any air contaminant source with an opacity in excess of twenty (20) percent for an aggregate of more than five (5) minutes in any one (1)hour or more than twenty (20) minutes in any twenty-four (24) hour period; provided, however, that for fuel burning installations with fuel burning equipment of input capacity greater than 600 million btu per hour, the permittee shall not cause, suffer, allow, or permit discharge of a visible emission from any fuel burning installation with an opacity in excess of twenty (20) percent (6-minute average) except for one six minute period per one (1) hour of not more than forty (40) percent opacity. Sources constructed or modified after July 7, 1992 shall utilize 6-minute averaging.

Consistent with the requirements of TAPCR Chapter 1200-03-20, due allowance may be made for visible emissions in excess of that permitted under TAPCR 1200-03-05 which are necessary or unavoidable due to routine startup and shutdown conditions. The facility shall maintain a continuous, current log of all excess visible emissions showing the time at which such conditions began and ended and that such record shall be available to the Technical Secretary or his representative upon his request.

TAPCR 1200-03-05-.01(1), TAPCR 1200-03-05-.03(6) and TAPCR 1200-03-05-.02(1)

D2. **General provisions and applicability for non-process gaseous emissions.** Any person constructing or otherwise establishing a non-portable air contaminant source emitting gaseous air contaminants after April 3, 1972, or relocating an air contaminant source more than 1.0 km from the previous position after November 6, 1988, shall install and utilize the best equipment and technology currently available for controlling such gaseous emissions.

TAPCR 1200-03-06-.03(2)

D3. **Non-process emission standards.** The permittee shall not cause, suffer, allow, or permit particulate emissions from non-process sources in excess of the standards in TAPCR 1200-03-06.

D4. **General provisions and applicability for process gaseous emissions.** Any person constructing or otherwise establishing an air contaminant source emitting gaseous air contaminants after April 3, 1972, or relocating an air contaminant source more than 1.0 km from the previous position after November 6, 1988, shall install and utilize equipment and technology which is deemed reasonable and proper by the Technical Secretary.

TAPCR 1200-03-07-.07(2)

D5. **Particulate emissions from process emission sources.** The permittee shall not cause, suffer, allow, or permit particulate emissions from process sources in excess of the standards in TAPCR 1200-03-07.

D6. **Sulfur dioxide emission standards.** The permittee shall not cause, suffer, allow, or permit Sulfur dioxide emissions from process and non-process sources in excess of the standards in TAPCR 1200-03-14. Regardless of the specific emission standard, new process sources shall utilize the best available control technology as deemed appropriate by the Technical Secretary of the Tennessee Air Pollution Control Board.

D7. **Fugitive Dust.**

(a) The permittee shall not cause, suffer, allow, or permit any materials to be handled, transported, or stored; or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, but not be limited to, the following:

1. Use, where possible, of water or chemicals for control of dust in demolition of existing buildings or structures, construction operations, grading of roads, or the clearing of land;

2. Application of asphalt, oil, water, or suitable chemicals on dirt roads, material stock piles, and other surfaces which can create airborne dusts;

3. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting or other similar operations.

(b) The permittee shall not cause, suffer, allow, or permit fugitive dust to be emitted in such manner to exceed five (5) minutes per hour or twenty (20) minutes per day as to produce a visible emission beyond the property line of the property on which the emission originates, excluding malfunction of equipment as provided in Chapter 1200-03-20.

TAPCR 1200-03-08

D8. **Open burning.** The permittee shall comply with the TAPCR 1200-03-04 for all open burning activities at the facility.

TAPCR 1200-03-04

D9. **Asbestos.** Where applicable, the permittee shall comply with the requirements of 1200-03-11-.02(2)(d) when conducting any renovation or demolition activities at the facility.

TAPCR 1200-03-11-.02(2)(d) and 40 CFR, Part 61

D10. **Annual certification of compliance.** The generally applicable requirements set forth in Section D of this permit are intended to apply to activities and sources that are not subject to source-specific applicable requirements contained in State of Tennessee and U.S. EPA regulations. By annual certification of compliance, the permittee shall be considered to meet the monitoring and related record keeping and reporting requirements of TAPCR 1200-03-09-.02(11)(e)1.(iii) and 1200-03-10-.04(2)(b)1 and compliance requirements of TAPCR 1200-03-09-.02(11)(e)3.(i). The permittee shall submit compliance certification for these conditions annually.

Revised 10/2011

SECTION E

SOURCE SPECIFIC EMISSION STANDARDS, OPERATING LIMITATIONS, and MONITORING, RECORDKEEPING and REPORTING REQUIREMENTS

37-0007	Facility Description:	Combined cycle plant consisting of three combustion turbine electric-generating units with dry low-NO_X combustors, water injection, and selective catalytic reduction for NO_X control; natural gas-fired auxiliary boiler (48.668 MMBtu/hr); two natural gas-fired heaters (23.0 MMBtu/hr each); mechanical draft cooling tower; emergency fire pump engine; and two distillate oil storage tanks.

Sections E1 and E2 apply to all sources in Section E of this permit unless otherwise noted.

E1 (SM1). **Fee payment:** actual emissions basis.

FEE EMISSIONS SUMMARY TABLE FOR MAJOR SOURCE 37-0007			
REGULATED POLLUTANTS	**ALLOWABLE EMISSIONS (tons per AAP)**	**ACTUAL EMISSIONS (tons per AAP)**	**COMMENTS**
Particulate Matter (PM)	N/A	AEAR	
PM_{10}	N/A	AEAR	
$PM_{2.5}$	N/A	AEAR	
SO_2	N/A	AEAR	
VOC	N/A	AEAR	
NO_X	N/A	AEAR	
Pb	N/A	AEAR	
CATEGORY OF MISCELLANEOUS HAZARDOUS AIR POLLUTANTS (HAP WITHOUT A STANDARD)*			
VOC FAMILY GROUP	N/A	AEAR	Fee emissions are included in VOC above. Maximum actual emissions.
NON-VOC GASEOUS GROUP	N/A	AEAR	Includes HCl, HF, Hg, and Se. Maximum actual emissions.
PM FAMILY GROUP	N/A	AEAR	Fee emissions are included in PM above. Includes Sb, As, Be, Cd, Cr, Co, Mn, and Ni. Maximum actual emissions.
CATEGORY OF SPECIFIC HAZARDOUS AIR POLLUTANTS (HAP WITH A STANDARD)**			
VOC FAMILY GROUP	N/A	N/A	
NON-VOC GASEOUS GROUP	N/A	N/A	
PM FAMILY GROUP	N/A	N/A	
CATEGORY OF NSPS POLLUTANTS NOT LISTED ABOVE***			
EACH NSPS POLLUTANT NOT LISTED ABOVE	N/A	N/A	

NOTES

AAP The **Annual Accounting Period** (**AAP**) is a twelve (12) consecutive month period that **begins each July 1st and ends June 30th of the following year**. The **present Annual Accounting Period began July 1, 2016 and ends June 30, 2017.** The **next Annual Accounting Period begins July 1, 2017 and ends June 30, 2018.**

N/A **N/A** indicates that no emissions are specified for fee computation.

AEAR **AEAR** indicates that an **A**ctual **E**missions **A**nalysis is **R**equired to determine the actual emissions of:

(1) **each regulated pollutant** (Particulate matter, SO_2, VOC, NO_X and so forth. See TAPCR 1200-03-26-.02(2)(i) for the definition of a regulated pollutant.),

(2) **each pollutant group** (VOC Family, Non-VOC Gaseous, and Particulate Family), and

(3) the **Miscellaneous HAP Category** under consideration during the **Annual Accounting Period**.

* **Category Of Miscellaneous HAP (HAP Without A Standard):** This category is made-up of hazardous air pollutants that do not have a federal or state standard. Each HAP is classified into one of three groups, the **VOC Family** group**, the Non-VOC Gaseous** group**,** or the **Particulate (PM) Family** group**. For fee computation**, the **Miscellaneous HAP Category** is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i).

** **Category Of Specific HAP (HAP With A Standard):** This category is made-up of hazardous air pollutants (HAP) that are subject to Federally promulgated Hazardous Air Pollutant Standards that can be imposed under Chapter 1200-03-11 or Chapter 1200-03-31. Each individual hazardous air pollutant is classified into one of three groups, the **VOC Family** group**, the Non-VOC Gaseous** group**,** or the **Particulate (PM) Family** group**. For fee computation**, each individual hazardous air pollutant of the **Specific HAP Category** is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(I).

*** **Category Of NSPS Pollutants Not Listed Above:** This category is made-up of each **N**ew **S**ource **P**erformance **S**tandard (**NSPS**) pollutant whose emissions are not included in the **PM**, **SO_2, VOC** or **NO_X** emissions from each source in this permit. **For fee computation**, each **NSPS pollutant not listed above** is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i).

The permittee shall:

(1) Pay major source annual **actual based emission fees**, as requested by the responsible official, for each annual accounting period (AAP) by July 1 of each year.

(2) Prepare an **actual emissions analysis** in accordance with the above **Fee Emissions Summary Table** for each AAP (July 1 of each year through June 30 of the following year). The **actual emissions analysis** shall include:

- **(a)** the completed **Fee Emissions Summary Table**,
- **(b)** each **AEAR** required by the above **Fee Emissions Summary Table, and**
- **(c)** the records required by Condition ***E2-5*** of this permit. These records shall be used to complete the **AEARs** required by the above **Fee Emissions Summary Table**.

(3) Submit the **actual emissions analysis** at the time the fees are paid in full.

(4) Calculate the fee due based upon the **actual emissions analysis**, and submit the payment on July 1st following the end of the **annual accounting period**. If any part of any fee imposed under TAPCR 1200-3-26-.02 is not paid within fifteen (15) days of the due date, penalties shall at once accrue as specified in TAPCR 1200-3-26-.02(8). Major sources may request an extension of time to file their emissions analysis with the Technical Secretary as specified in Condition A8(c)5 of this permit. Emissions for regulated pollutants shall not be double counted as specified in Condition A8(d) of this permit.

The Tennessee Air Pollution Control Division will bill the permittee no later than April 1 prior to the end of each **annual accounting period**. The annual emission fee is due July 1 following the end of each **annual accounting period**. If any part of any fee imposed under TAPCR 1200-03-26-.02 is not paid within fifteen (15) days of the due date, penalties shall at once accrue as specified in TAPCR 1200-03-26-.02(8). Emissions for regulated pollutants shall not be double counted as specified in Condition A8(d) of this permit.

The Actual Emissions Analysis and fee payment shall be submitted to the following addresses:

Actual Emissions Analysis:

Tennessee Department of Environment and Conservation
Division of Air Pollution Control
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 15^{th} Floor
Nashville, TN 37243

Fee Payment:

Tennessee Department of Environment and Conservation
Division of Fiscal Services
Consolidated Fee Section – APC
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 10^{th} Floor
Nashville, TN 37243

TAPCR 1200-03-26-.02 (3) and (9), and 1200-03-09-.02(11)(e)1 (iii) and (vii)

E2. General Facility Conditions
E2-1 (SM1). Reporting requirements.

(a) **Semiannual reports.** Semiannual reports shall cover the 6-month periods from **January 1** through **June 30** and **July 1** to **December 31**, and shall be submitted within 60 days after the end of each six-month period. All instances of deviations from permit requirements must be clearly identified in these reports and the reports must be certified by a responsible official. Semiannual reports shall include:

(1) Reports of any monitoring, recordkeeping and calculated emission rates required by conditions ***E2-3, E2-5, and E3-10*** of this permit. A summary report of this data is acceptable provided there is sufficient information to enable the Technical Secretary to evaluate compliance.

(2) The visible emission evaluation readings from condition ***E2-2*** of this permit if required. A summary report of this data is acceptable provided there is sufficient information to enable the Technical Secretary to evaluate compliance.

(3) Identification of all instances of deviations from **ALL PERMIT REQUIREMENTS**.

These reports must be certified by a responsible official consistent with condition B4 of this permit and shall be submitted to The Technical Secretary at the address in Condition E2-1(b) of this permit.
TAPCR 1200-03-09-.02(11)(e)1.(iii)

(b) **Annual compliance certification.** The permittee shall submit annually compliance certifications with terms and conditions contained in Sections A, B, D, & E of this permit, including emission limitations, standards, or work practices. This compliance certification shall include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

(1) The identification of each term or condition of the permit that is the basis of the certification;

(2) The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required by this permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Act, which prohibits knowingly making a false certification or omitting material information.

(3) Reserved.

(4) The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in E2-1(b)(2) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion* or exceedance** as defined below occurred; and

(5) Such other facts as the Technical Secretary may require to determine the compliance status of the source.

* “Excursion” shall mean a departure from an indicator range established for monitoring under this paragraph, consistent with any averaging period specified for averaging the results of the monitoring.

** “Exceedance” shall mean 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 (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

The certification shall cover the 12-month period from **January 1** to **December 31** of each calendar year and shall be submitted within 60 days after the 12-month period ends. These certifications shall be submitted to: **TN APCD and EPA**

Technical Secretary Division of Air Pollution Control Johnson City Environmental Field Office 2305 Silverdale Road Johnson City, TN 37601-2162 e-mail: APC.JCEFO@tn.gov	and	Air and EPCRA Enforcement Branch US EPA Region IV 61 Forsyth Street, SW Atlanta, Georgia 30303

40 CFR Part 70.6(c)(5)(iii) as amended in the Federal Register Vol.79, No. 144, July 28, 2014, pages 43661 through 43667

E2-2. Visible emissions from this facility shall not exhibit greater than ten percent (10%) opacity. Opacity data reduction shall be accomplished utilizing procedures outlined in the current 40 CFR 60, Appendix A, Method 9 (six-minute average). In accordance with Rule 1200-03-05-.02 of the Tennessee Air Pollution Control Regulations, due allowance may be made for visible emissions in excess of this standard which are unavoidable due to routine startup and shutdown conditions.

Compliance Method: Compliance with this condition shall be determined by the procedures of the Division's Opacity Matrix dated September 11, 2013 (Attachment 1).

TAPCR 1200-03-05-.01(3), agreement letter dated April 7, 2010, Condition 33 of construction permit 963140F

E2-3. A log of the following information must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative:

(a) Monthly natural gas and #2 fuel oil usage for each combustion turbine
(b) Monthly natural gas usage for duct firing for each CT/HRSG unit.
(c) Monthly natural gas usage for the auxiliary boiler
(d) Monthly natural gas usage for the fuel heaters
(e) Monthly natural gas sulfur content
(f) Deliveries of fuel oil to the storage tanks (gallons/ month and gallons/12 consecutive months)
(g) Sulfur analyses of fuel oil
(h) Hours of testing operation of the emergency fire pump
(i) Maintenance activities

This log must be retained for a period of not less than five years.

TAPCR 1200-03-10-.02(2)(a), Condition 34 of construction permit 963140F

E2-4. Routine maintenance, as required to maintain specified emission limits, shall be performed on the air pollution control device(s). Maintenance records shall be recorded in a suitable permanent form and kept available for inspection by the Division. These records must be retained for a period of not less than five years.

TAPCR 1200-03-09-.01(1)(d), Condition 35 of construction permit 963140F

E2-5. The permittee has requested facility-wide emission limits to ensure that PSD significance thresholds are not exceeded for each pollutant. The specific emission limits for each PSD pollutant are as follows:

Pollutant	Emission Limit (tons/12 consecutive months)
Filterable PM	499
Filterable PM_{10}	318
Filterable $PM_{2.5}$	146
SO_2	27,770
VOC	99.6
NO_X	8,649
CO	597
Lead	0.678
SO_3	80.2

Compliance method: To demonstrate compliance with these limits and to calculate actual emissions for fee purposes, the permittee shall provide to the Division a John Sevier Fossil Plant Emissions Summary Ledger, which incorporates all significant emissions activities for the facility. Emissions estimating and reporting methods in the Ledger shall be approved by the Division, and designed to utilize regularly accepted industry estimating practices. The Ledger may use, but is not limited to estimating methods developed from site-specific emissions source testing, continuous Emissions Monitoring Systems (CEMS), material usage and production information for specific emissions and site-wide activities, industry-specific emission factors provided by regulatory agencies or trade organizations, and other methods approved by the Division. All modifications to the Ledger shall be approved by the Division.

TAPCR 1200-03-09-.01(1)(d), agreement letter dated April 7, 2010. TAPCR 1200-03-26-.02(9)(g)2. Conditions 39, 40, 41, 42, 43, and 44 of construction permit 963140F

E2-6. Compliance Assurance Monitoring (CAM)

This facility is exempt from CAM requirements (40 CFR Part 64) as follows:

Pollutant	CAM Exemption	Description
NO_X	§64.2(b)(1)(iii)	This pollutant is subject to Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.
SO_2	§64.2(a)(2)	The combustion turbines do not meet general applicability criteria for this pollutant (no add-on control device for SO_2).
CO	§64.2(b)(1)(vi)	This pollutant is subject to emission limitations and standards contained in a Part 70 or 71 permit. The permit specifies continuous compliance methods (CEMS) for these limits.
PM	§64.2(a)(2)	The combustion turbines do not meet general applicability criteria for this pollutant (no add-on control device for PM).
VOC	§64.2(a)(3)	The combustion turbines do not meet general applicability criteria for this pollutant (pre-control VOC emissions from each PSEU are less than 100 tons/year).

TAPCR 1200-03-09-.03(8), 40 CFR 64

E2-7. Reserved. SM1 deletes this requirement.

E2-8 (SM1). Identification of Responsible Official, Technical Contact, and Billing Contact

(a) The application that was utilized in the preparation of this permit is dated April 22, 2013, and is signed by Dustin P. Watson, Plant Manager. If this person terminates employment or is assigned different duties and is no longer a Responsible Official for this facility as defined in part 1200-03-09-.02(11)(b)21 of the Tennessee Air Pollution Control Regulations, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification must be in writing and must be submitted within thirty (30) days of the change. The notification shall include the name and title of the new Responsible Official and certification of truth and accuracy. All representations, agreement to terms and conditions, and covenants made by the former Responsible Official that were used in the establishment of the permit terms and conditions will continue to be binding on the facility until such time that a revision to this permit is obtained that would change said representations, agreements, and/or covenants.

(b) The application that was utilized in the preparation of this permit is dated April 22, 2013, and identifies Tonya Bailey, Environmental Scientist, as the Principal Technical Contact for the permitted facility. If this person terminates employment or is assigned different duties and is no longer the Principal Technical Contact for this facility, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification must be in writing and must be submitted within thirty (30) days of the change. The notification shall include the name and title of the new Principal Technical Contact and certification of truth and accuracy.

(c) The application that was utilized in the preparation of this permit is dated April 22, 2013, and identifies James W. Osborne, Jr. as the Billing Contact for the permitted facility. If this person terminates employment or is assigned different duties and is no longer the Billing Contact for this facility, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification must be in writing and must be submitted within thirty (30) days of the change. The notification shall include the name and title of the new Billing Contact and certification of truth and accuracy.

37-0007-14	**Combustion Turbines**: three (3) combustion turbine (CT) electric generating units (General Electric 7FA units) that will be operated in either simple-cycle (EU-12, EU-13 & EU-14) or combined cycle (EU-15, EU-16, & EU-17) configuration. For simple-cycle operation, the units will be fired with either natural gas (NG) or low-sulfur, distillate (No 2) fuel oil. Dry-low- NO_X (DLN) combustors will be used to control nitrogen oxides (NO_X) emissions during NG firing and water injection will be used to control NO_X emissions during fuel oil firing. Selective Catalytic Reduction will be used for NO_X control and Catalytic Oxidation for CO and VOC control during combined cycle operation. Conditions E3-1 through E3-12 apply.

E3-1. This source consists of three (3) combustion turbine (CT) units with nominal heat input and generating capacity as follows:

Stack Identification	Type of Firing	Rated Input Capacity (MMBtu/hr)	Other Rating Capacity Electrical-Generation Output (MW)
EU-12, EU-13 & EU-14 (Combustion Turbine Stacks)	**Simple Cycle:** Dry Low-NO_X Natural Gas (NG) Fired Combustor or #2 Fuel Oil (FO) Firing	1,755.9 Natural Gas 1,904 Fuel Oil	177 MW Natural Gas 187 MW Fuel Oil
EU-15, EU-16 & EU-17 (Identical)	**Combined Cycle:** Dry Low-NO_X Natural Gas (NG) Fired Combustor with NG-Fired Duct Burner (DB) or #2 Fuel Oil (FO) Firing. Selective catalytic reduction for NO_X control and oxidation catalyst for CO and VOC control	1,751.1 Natural Gas 2,083.1 NG + DB 1,896.3 #2 Fuel Oil	175 MW Natural Gas 175 MW Natural Gas + Duct Burner 187 MW #2 Fuel Oil

TAPCR 1200-03-09-.01(1)(d), Condition 2 of construction permit 963140F

E3-2. Only natural gas and #2 fuel oil, with a sulfur content not to exceed 0.05% by weight shall be used as fuels for the combustion turbines. This limit is established pursuant to the agreement letter dated April 7, 2010.

TAPCR 1200-03-09-.01(1)(d), Condition 3 of construction permit 963140F

Compliance Method: Compliance with this fuel restriction shall be assured by the recordkeeping of **Condition E2-3** of this permit. TAPCR 1200-03-09-.02(11)(e)1.(iii)

E3-3. Particulate matter (TSP) emitted from each combustion turbine unit of the fuel-burning installation shall not exceed 0.100 lb/MMBtu of heat input. This emission limit is established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control Regulations.

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition E3-2**. Compliance is based upon the following AP-42 emission factors for natural gas and fuel oil combustion in turbines:

Pollutant	Emission Factor (pounds per million Btu)
Particulate matter	0.012 (fuel oil)
	0.0066 (natural gas)
Data from AP-42, Table 3.1-2a (enclosed as Attachment 2)	

TAPCR 1200-03-06-.01(7) and 1200-03-09-.02(11)(e)1.(iii), Condition 4 of construction permit 963140F

E3-4. Sulfur dioxide (SO_2) emitted from each combustion turbine unit of this fuel-burning installation shall not exceed the following limits (in pounds per million British Thermal Units of heat input).

Pollutant	Emission Limits while firing natural gas (lb/MMBtu)	Emission Limits while firing fuel oil (lb/MMBtu)
SO_2	0.0012	0.05

These emission limits are established pursuant to Rule 1200-03-14-.01(3) of the Tennessee Air Pollution Control Regulations and the agreement letter dated April 7, 2010.

TAPCR 1200-03-14-.01(3)

Compliance Method: Compliance with this condition shall be assured by the use of pipeline natural gas and No. 2 fuel oil with a sulfur content no to exceed 0.05% by weight and by the logs required in **Condition E2-3** of this permit.

TAPCR 1200-03-09-.02(11)(e)1.(iii), Condition 5 of construction permit 963140F

E3-5. Exhaust nitrogen oxides concentrations when operating in combined cycle mode shall not exceed 3.5 parts per million dry volume (ppmvd) corrected to 15% oxygen (24 operating hour average) when firing natural gas and 30 ppmvd corrected to 15% oxygen (15 operating day average) when firing No. 2 fuel oil. Emissions during the following conditions are not included in calculating compliance with these limits:

Tuning & Maintenance sessions normally occur after a combustor change-out, a major repair or maintenance to a combustor, or other similar maintenance circumstances. Tuning sessions are completed periodically to optimize emissions reductions from the combustion turbine process.

Fuel Switching - The 30-minute period starting at 90 MW after a turbine has decreased output to accommodate the fuel switch.

Combined Cycle Startup – A startup period for a unit is the period of operation from the fuel ignition in that unit until 90 MW CT output is attained. Emission exclusions for any individual startup period shall not exceed six (6) hours.

Combined Cycle Shutdown – A shutdown period for a unit begins at 90 MW CT output, prior to the cessation of fuel combustion for that unit. Emission exclusions for any individual shutdown period shall not exceed one (1) hour.

Combined Cycle Low-load operation – Low-load operation for a unit is operation below 90 MW CT output, not including periods of startup or shutdown for that unit. Emission exclusions for any individual period of low-load operation shall not exceed two (2) hours.

These limits are established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control Regulations and the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by compliance with **Conditions E3-8, E3-9, and E3-10** of this permit.

TAPCR 1200-03-06-.01(7) and 1200-03-09-.02(11)(e)1.(iii), Condition 6 of construction permit 963140F

E3-6. The source shall comply with the applicable requirements of 40 CFR Part 63 Subpart YYYY, as provided below:

MACT Requirements (40 CFR 63 Subpart YYYY)	
Rule Citation	**Requirement**
§63.6095(d)	**Stay of standards for gas-fired subcategories**. If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.
§63.6100 Table 1	Limit the concentration of formaldehyde to 91 parts per billion by dry volume (ppbvd) or less at 15% O_2.
§63.6105(a)	Comply with the emission limitations and operating limitations at all times except during startup, shutdown, and malfunctions.
§63.6105(b)	Operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air

MACT Requirements (40 CFR 63 Subpart YYYY)	
Rule Citation	**Requirement**
	pollution control practices for minimizing emissions at all times, including startup, shutdown, and malfunction.
§§63.6115, 63.6120, Table 3	Conduct performance tests on an annual basis. Comply with the requirements of §63.6120, §63.6145(f), and Table 3 to Subpart YYYY for performance tests.
§63.6125(a), §63.6140(a), Tables 2 and 5	Continuously monitor the oxidation catalyst inlet temperature. Maintain the 4-hour rolling average inlet temperature within the range suggested by the catalyst manufacturer.
§63.6135	Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), conduct all parametric monitoring at all times the stationary combustion turbine is operating. Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. Use all data collected during all other periods in assessing the performance of the control device or in assessing emissions from the stationary combustion turbine.
§63.6140(c)	Consistent with §63.6(e) and §63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in accordance with §63.6(e)(1)(i).
§63.6150	Submit reports in accordance with §63.6150 and Table 6 to Subpart YYYY.
§63.6155 and §63.6160	Keep records in accordance with §63.6155 and §63.6160.
§63.6165	Applicability of General Provisions – see Table 7 to Subpart YYYY.

TAPCR 1200-03-09-.03(8), 40 CFR 63 Subpart YYYY

E3-7. The source shall comply with the applicable requirements of 40 CFR Part 60 Subpart KKKK, as provided below:

NSPS Requirements (40 CFR 60 Subpart KKKK)	
Rule Citation	**Requirement**
§60.4320, §60.4325, Table 1 to Subpart KKKK	Comply with the NO_X emission limits in Table 1 to Subpart KKKK. If two or more turbines are connected to a single generator, each turbine must meet the NO_X emission limits. • 15 ppm at 15% O_2 or 0.43 lb/MWh of useful output when firing natural gas (30-day rolling average) • 42 ppm at 15% O_2 or 1.3 lb/MWh of useful output when firing fuels other than natural gas (30-day rolling average) Comply with §60.4325 when burning mixtures of natural gas and distillate oil.
§60.4330	Comply with SO_2 emission limit of 0.90 lb/MWh gross output or do not burn any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2 per MMBtu of heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.
§60.4333(a)	Operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.
§60.4335(b), §60.4340(b),	Install, certify, maintain, and operate a continuous emission monitoring system (CEMS)

NSPS Requirements (40 CFR 60 Subpart KKKK)	
Rule Citation	**Requirement**
§60.4345	consisting of a NO_X monitor and a diluent gas (O_2 or CO_2) monitor, to determine the hourly NO_X emission rate in ppm. NO_X CEMS must comply with the specifications of §60.4345.
§60.4350, §60.4380	Use CEMS data as specified in §60.4350 and §60.4380 to identify excess emissions and monitor downtime.
§60.4365	You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input for units located in continental areas.
§60.4370(c)	Custom monitoring schedule. See Attachment 3 of this permit.
§60.4375(a), §60.4395	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 startup, shutdown, and malfunction. All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each six-month period. Reports shall be submitted to: Division of Air Pollution Control Compliance Validation Program William R. Snodgrass Tennessee Tower 312 Rosa L Parks Avenue, 15th Floor Nashville, TN 37243

TAPCR 1200-03-09-.03(8), Condition 8 of construction permit 963140F, 40 CFR 60 Subpart KKKK

E3-8. NO_X and CO emissions from each CT shall be measured with continuous emissions monitoring systems (CEMS). CO CEMS shall be installed and maintained in accordance with the requirements of 40 CFR 60 Appendix B, Performance Specification 4 or 4A. NO_X CEMS shall be installed and maintained in accordance with 40 CFR 75.

Each CO and NO_X CEMS shall be fully operational for at least ninety five percent (95%) of the operating time of the monitored unit during each calendar quarter. An operational availability of less than this amount may be the basis for declaring a unit in noncompliance with the applicable monitoring requirement, unless the reasons for the failure to maintain this level of availability are accepted by the Division as legitimate malfunctions of the instruments. If any CEMS is inoperative for more than seven consecutive days, the use of a backup monitor may be required.

TAPCR 1200-03-09-.02(11)(e)1.(iii), TAPCR 1200-03-10-.04, Condition 9 of construction permit 963140F

E3-9. Quality assurance checks shall be performed on each CEMS in accordance with the requirements of 40 CFR Part 75. The quality assurance checks shall consist of a repetition of the relative accuracy portion of the Performance Specification Test.

Within ninety (90) days of each major modification or major repair of any emissions monitor, diluent monitor, or electronic signal combining system, a repeat of the performance specification test shall be conducted, and a written report of it submitted to the Technical Secretary as proof of the continuous operation of the emissions monitoring system within acceptable limits.

TAPCR 1200-03-10-.02(1)(a)

E3-10 (SM1). The following information shall be submitted to the Technical Secretary in the semiannual report required by **Condition E2-1(a):**

(a) For NO_X, the report shall include emission averages, in the units of the applicable standard (ppmvd corrected to 15% O_2), for each averaging period during operation of the source (24 operating hour average when firing natural gas and 15 operating day average) when firing No. 2 fuel oil).

(b) The report shall include the date and time identifying each period during which the system was inoperative (except for zero and span checks) and the nature of system repairs or adjustments. The Technical Secretary may require proof of system performance whenever system repairs or adjustments have been made.

(c) The report shall include written reports of the quality assurance checks required by **Condition E3-9**.

(d) When the system has been inoperative, repaired, or adjusted, such information shall be included in the report.

E3-11. Reserved. SM1 deletes this requirement.

E3-12 (SM1). Transport Rule (TR) Requirements

The permittee shall comply with the applicable provisions of 40 CFR 97 Subparts AAAAA (TR NO_X Annual Trading Program), BBBBB (TR NO_X Ozone Season Trading Program), and CCCCC (TR SO_2 Group 1 Trading Program). Specific trading program requirements are included in Attachment 4.

TAPCR 1200-03-09-.03(8) and 40 CFR §52.2240 and §52.2241, 40 CFR §§97.401 – 97.435, §§97.501 – 97.535, §§97.601 – 97.635

37-0007-15	<u>**Natural Gas Fired Auxiliary Boiler (EU-20)**</u>: Cleaver-Brooks Model CBL-LN. The auxiliary boiler provides steam to the steam turbine gland seals during preheating and turbine startup. The boiler is equipped with low NO_X burners and flue gas recirculation. Conditions E4-1 through E4-7 apply.

E4-1. This source consists of one (1) natural gas fired auxiliary boiler Unit EU-20 with nominal heat input as follows:

Natural Gas Fired Auxiliary Boiler	Type of Firing	Rated Input Capacity (MMBtu/hr)
EU-20	NG-fired Low-NO_X Burner	48.668

TAPCR 1200-03-09-.01(1)(d), Condition 13 of construction permit 963140F

E4-2. Only natural gas shall be used as fuel for the auxiliary boiler. The sulfur content of the natural gas shall not exceed 0.4 grains of sulfur per 100 standard cubic feet. This limit is established pursuant to Rule 1200-03-14-.01(3) Tennessee Air Pollution Control Regulations and the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition is based on the information provided with the application dated April 22, 2013. Compliance shall be assured by annual certification, as required in **Condition E2-1(b)**.

TAPCR 1200-03-14-.01(3), Condition 14 of construction permit 963140F

E4-3. Filterable particulate matter (PM) emitted from the auxiliary boiler shall not exceed 0.25 lb/MMBtu of heat input. This emission limit is established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control Regulations and the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by the use of pipeline natural gas.

TAPCR 1200-03-06-.01(7), Condition 15 of construction permit 963140F

E4-4. Sulfur dioxide (SO_2) emitted from the auxiliary boiler shall not exceed 0.0012 lb/MMBtu.

This emission limit is established pursuant to Rule 1200-03-14-.01(3) Tennessee Air Pollution Control Regulations and the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by the use of pipeline natural gas.

TAPCR 1200-03-09-.01(1)(d), Condition 16 of construction permit 963140F

E4-5. The use of natural gas only as fuel shall represent Maximum Achievable Control Technology (MACT) for the auxiliary boiler, pursuant to Chapter 1200-03-31 of the Tennessee Air Pollution Control Regulations.

E4-6. This source shall comply with all applicable requirements of 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. All required reporting and recordkeeping for the subject unit shall be accomplished in accordance with section §60.48c.

40 CFR 60 Subpart Dc Requirements		
Rule	**Title**	**Description**
§60.48c(a)	Date of Construction	Notification in 30 days after construction date including information specified in 60.7 and 60.48c.
§60.48c(a)	Actual Date of Initial Startup	Notification within 15 days after actual start-up date including information specified in 60.7 and 60.48c.
§60.48c(g)(2)	Fuel records	Records indicating the total monthly amount of fuel combusted in each steam generating unit.
§60.48c(i)	Recordkeeping	Maintain records for a period of five (5) years.

TAPCR 1200-03-09-.03(8), Condition 18 of construction permit 963140F, 40 CFR 60 Subpart Dc

E4-7 (SM1). Boiler MACT requirements (40 CFR 63 Subparts DDDDD and JJJJJJ):

(a) Pursuant to §63.11210(i), boilers located at existing major sources of HAP that limit their potential to emit such that the existing major source becomes an area source, must comply with the applicable provisions as specified in paragraphs §§63.11210(i)(1) through (3).

(b) Pursuant to §63.11195(e), a gas-fired boiler is not subject to any requirements in 40 CFR 63 Subpart JJJJJJ. Pursuant to §63.11237, a gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

(c) The Technical Secretary has determined that the requirements of 40 CFR 63 Subpart DDDDD are no longer applicable to this facility, due to the change in source category status (retirement of coal-fired boilers). The Technical Secretary has also determined that this source is a "gas-fired boiler" as defined by 40 CFR 63 Subpart JJJJJJ, and the requirements of Subpart JJJJJJ do not apply to this source.

TAPCR 1200-03-09-.03(8), 40 CFR 63 Subparts DDDDD and JJJJJJ

37-0007-16	**<u>Two Natural Gas-Fired Heaters (EU-18 and EU-19)</u>**: Two natural gas-fired water heaters process natural gas fuel for the CT units. The heaters evaporate any liquid droplets formed as the natural gas is stepped down from pipeline pressures. This process is needed for proper operation of the CT units' dry low-NO_X burners. Conditions E5-1 through E5-6 apply.

E5-1. This source consists of two (2) natural gas fired heaters Unit EU-18 and EU-19 with nominal heat input as follows:

Natural Gas Fired Heaters	Type of Firing	Rated Input Capacity MMBtu/Hr.
Units EU-18 and EU-19	NG-fired Low-NO_X Burner	23.0 each unit

TAPCR 1200-03-09-.01(1)(d), Condition 19 of construction permit 963140F

E5-2. Only natural gas shall be used as fuels for the fuel heaters. The sulfur content of the natural gas shall not exceed 0.4 grains of sulfur per 100 standard cubic feet. These limits are established pursuant to the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition is based on the information provided with the application dated April 22, 2013. Compliance shall be assured by annual certification, as required in **Condition E2-1(b)**.

TAPCR 1200-03-09-.01(1)(d), Condition 20 of construction permit 963140F

E5-3. Filterable particulate matter (PM) emitted from the fuel heaters shall not exceed 0.25 lb/MMBtu. This emission limit is established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control Regulations.

Compliance Method: Compliance with this condition shall be assured by the use of pipeline natural gas.

TAPCR 1200-03-06-.01(7) and 1200-03-09-.01(1)(d), Condition 21 of construction permit 963140F

E5-4. Sulfur dioxide (SO_2) emitted from the auxiliary boiler shall not exceed 0.0012 lb/MMBtu. This emission limit is established pursuant to the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by the use of pipeline natural gas.

TAPCR 1200-03-09-.01(1)(d) and 1200-03-14-.01(3), Condition 22 of construction permit 963140F

E5-5 (SM1). Boiler MACT requirements (40 CFR 63 Subparts DDDDD and JJJJJJ):

(a) Pursuant to §63.11210(i), boilers located at existing major sources of HAP that limit their potential to emit such that the existing major source becomes an area source, must comply with the applicable provisions as specified in paragraphs §§63.11210(i)(1) through (3).

(b) Pursuant to §63.11193, an owner or operator of an industrial, commercial, or institutional boiler, as defined in §63.11237, is subject to 40 CFR 63 Subpart JJJJJJ if the boiler is located at, or is part of, an area source of hazardous air pollutants.

(i) Pursuant to §63.11237, “boiler” means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of “boiler.”

(ii) Pursuant to §63.11237, “process heater” means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials.

(c) The Technical Secretary has determined that the requirements of 40 CFR 63 Subpart DDDDD are no longer applicable to this facility, due to the change in source category status (retirement of coal-fired boilers). The Technical Secretary has also determined that this source is a “process heater” as defined by 40 CFR 63 Subpart JJJJJJ, and the requirements of Subpart JJJJJJ do not apply to this source.

TAPCR 1200-03-09-.03(8), 40 CFR 63 Subparts DDDDD and JJJJJJ

E5-6. This source shall comply with all applicable requirements of 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. All required reporting and recordkeeping for the subject unit shall be accomplished in accordance with section §60.48c.

40 CFR 60 Subpart Dc Requirements		
Rule	**Title**	**Description**
§60.48c(a)	Date of Construction Notification	Notification in 30 days after construction date including information specified in 60.7 and 60.48c.
§60.48c(a)	Actual Date of Initial Start-Up Notification	Notification within 15 days after actual start-up date including information specified in 60.7 and 60.48c.
§60.48c(g)(3)	Fuel records	Records indicating the total monthly amount of fuel combusted in each steam generating unit.
§60.48c(i)	Recordkeeping	Maintain records for a period of five (5) years.

TAPCR 1200-03-09-.03(8), Condition 24 of construction permit 963140F, 40 CFR 60 Subpart Dc

37-0007-17	<u>Mechanical Draft Cooling Tower</u>: Cooling tower consisting of an array of 12 individual cells (EU-21

	through EU-32). Conditions E6-1 through E6-3 apply.

E6-1. The recirculation rate for the process cooling water shall not exceed 259,000 gallons per minute (10,813,250 pounds per hour on a daily average basis). The Technical Secretary may require the permittee to prove compliance with this rate.

Compliance Method: Compliance with this condition shall be assured by annual certification, as required in **Condition E2-1(b)**.

TAPCR 1200-03-09-.01(1)(d), Condition 25 of construction permit 963140F

E6-2. Particulate matter emitted from this source shall not exceed 0.238 pounds per hour per cell. This limit is established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control Regulations and the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition is based on the emission calculations submitted with the application dated April 22, 2013. Maximum hourly emissions are calculated using the total cooling-water circulation rate (259,000 gpm), drift efficiency (0.001%), and blowdown water analysis (2,209 ppm). Compliance with this condition shall be assured by annual certification, as required in **Condition E2-1(b)**.

TAPCR 1200-03-06-.01(7) and 1200-03-09-.01(1)(d), Condition 26 of construction permit 963140F

E6-3. Only process cooling water shall enter the tower. No treatment chemicals containing Chromium or Volatile Organic Compounds shall be used in the cooling water treatment. This requirement is established pursuant to the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by annual certification, as required in **Condition E2-1(b)**.

TAPCR 1200-03-09-.01(1)(d), Condition 27 of construction permit 963140F

37-0007-18	<u>**Diesel Engine**</u>: Emergency Fire Pump (EU-33), lean burn, 252 brake horsepower diesel engine, RICE, NSPS. Conditions E7-1 through E7-3 apply.

E7-1. Only #2 or distillate fuel oil, with a sulfur content not to exceed 0.05 percent by weight, shall be used as fuel for the emergency fire pump. This limit is established pursuant to the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by annual certification, as required in **Condition E2-1(b)**.

TAPCR1200-03-09-.01(1)(d), Condition 29 of construction permit 963140F

E7-2. Hours of operation for the IC engine-driven emergency fire pump shall not exceed 50 hours during any period of twelve (12) consecutive months.

Compliance Method: Compliance with this limit shall be demonstrated with records required by **Condition E2-3** of this permit.

TAPCR 1200-03-09-.01(1)(d), Condition 30 of construction permit 963140F

E7-3. Upon startup of this new source, operation of the emergency fire pump shall be subject to all applicable requirements of 40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines:

(a) Emissions from the subject unit shall meet all applicable emissions standards specified in section §60.4205.
(b) Fuel used in the subject unit shall meet all applicable fuel requirements specified in section §60.4207.
(c) Monitoring for the subject unit shall meet all applicable monitoring requirements specified in section §60.4209, including the installation of a non-resettable hour meter prior to startup of the engine.
(d) Compliance shall be demonstrated in accordance with the compliance requirements specified in section §60.4211. (Paragraph (b) or paragraph (c) of that section will apply, depending upon the model year of the subject unit.)

TAPCR 1200-03-09-.03(8), Condition 31 of construction permit 963140F, 40 CFR 60 Subpart IIII

37-0007-19	**Two Distillate-Oil Storage Tanks**: TK-1 and TK-2, 2,000,000 gallons capacity each. Condition E8-1 applies.

E8-1. Tank turnovers shall not exceed 5 turnovers per tank during any period of twelve (12) consecutive months. This limitation is established pursuant to the agreement letter dated April 7, 2010.

Compliance Method: Compliance with this condition shall be assured by the records required by **Condition E2-3(f)** of this permit. One turnover is equal to 2,000,000 gallons of fuel delivered to the tank.

TAPCR1200-03-09-.01(1)(d), Condition 32 of construction permit 963140F

END OF SIGNIFICANT MODIFICATION #1 TO PERMIT NUMBER 567175

ATTACHMENT 1

OPACITY MATRIX DECISION TREE FOR VISIBLE EMISSION EVALUATION METHOD 9 DATED SEPTEMBER 11, 2013

Decision Tree PM for Opacity for Sources Utilizing EPA Method 9*

Notes:

PM = Periodic Monitoring required by 1200-03-09-.02(11)(e)(iii).

This Decision Tree outlines the criteria by which major sources can meet the periodic monitoring and testing requirements of Title V for demonstrating compliance with the visible emission standards set forth in the permit. It is not intended to determine compliance requirements for EPA's Compliance Assurance Monitoring (CAM) Rule (formerly referred to as Enhanced Monitoring – Proposed 40 CFR 64).

Examine each emission unit using this Decision Tree to determine the PM required.*

Use of continuous emission monitoring systems eliminates the need to do any additional periodic monitoring.

Visible Emission Evaluations (VEEs) are to be conducted utilizing EPA Method 9. The observer must be properly certified to conduct valid evaluations.

Typical Pollutants
Particulates, VOC, CO, SO_2, NO_x, HCl, HF, HBr, Ammonia, and Methane.

Initial observations are to be repeated within 90 days of startup of a modified source, if a new construction permit is issued for modification of the source.

A VEE conducted by TAPCD personnel after the Title V permit is issued will also constitute an initial reading.

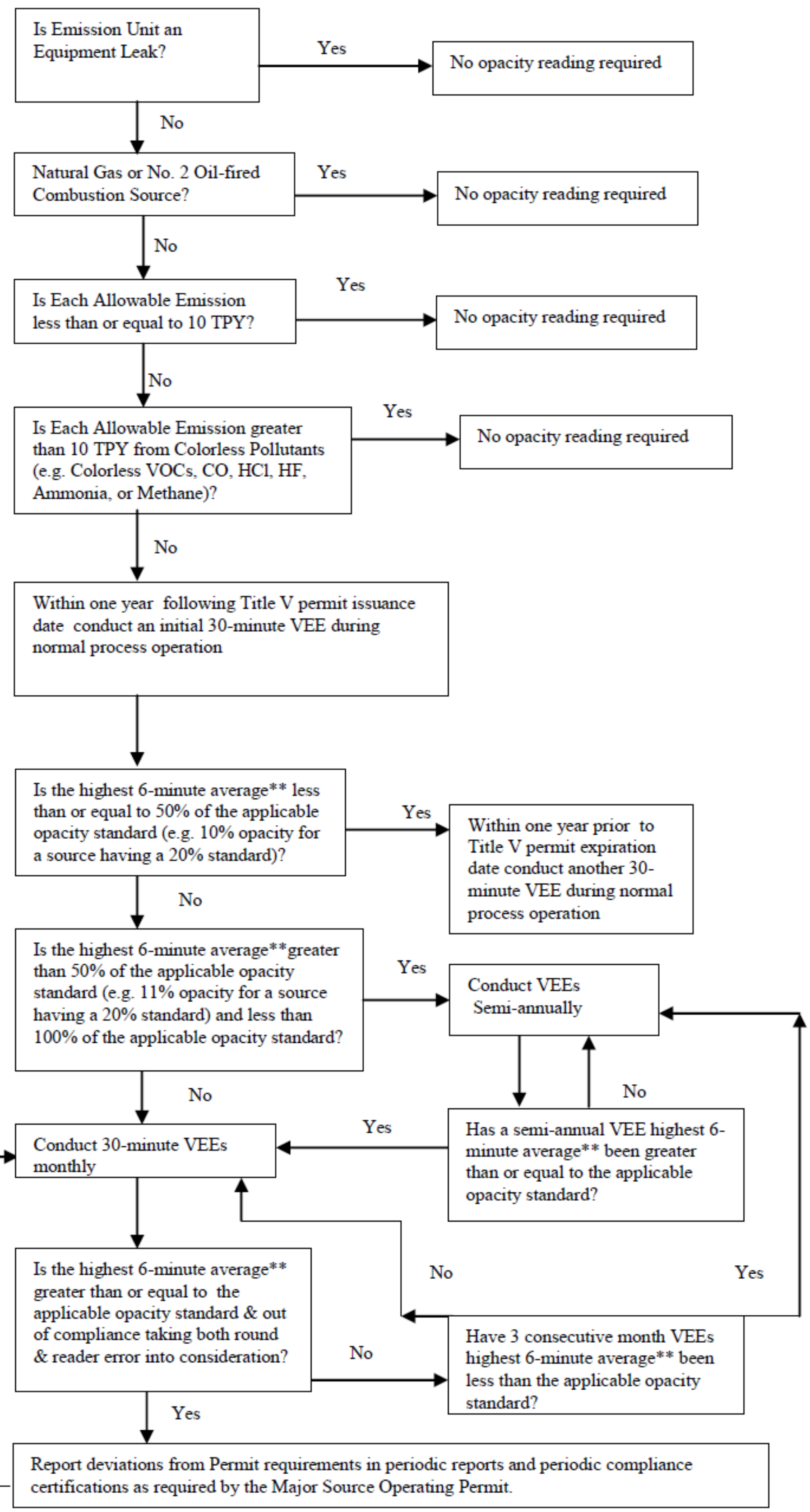
Reader Error
EPA Method 9, Non-NSPS or NESHAPS stipulated opacity standards:
The TAPCD guidance is to declares non-compliance when the highest six-minute average** exceeds the standard plus 6.8% opacity (e.g. 26.8% for a 20% standard).

EPA Method 9, NSPS or NESHAPS stipulate opacity standards:
EPA guidance is to allow only engineering round. No allowance for reader error is given.

*Not applicable to Asbestos manufacturing subject to 40 CFR 61.142

**Or second highest six-minute average, if the source has an exemption period stipulated in either the regulations or in the permit.

Dated June 18, 1996
Amended September 11, 2013



ATTACHMENT 2

EMISSION CALCULATIONS FOR
NATURAL GAS AND FUEL OIL COMBUSTION IN TURBINES

COMBUSTION TURBINE PROCESS DESCRIPTION

Three identical combustion turbine (CT) electric generating units are located at John Sevier Combined Cycle Plant (JSCC). The CT units can operate in either simple cycle or combined cycle configuration. The CT units operate as either peaking or reserve generating capacity with a total plant generating output of 940 megawatts (180 MW each CT generator and 400 MW single steam turbine generator). The CT units began commercial operation on April 30, 2012.

The CT units are General Electric Model 7FA and are designed to burn either natural gas or low-sulfur No. 2 fuel oil. For combined cycle operation, each CT unit has a heat recovery steam generator (HRSG) unit equipped with duct burners and share a single condensing steam turbine generator. The heat input ratings at 59°F for simple cycle operation are 1,755.9 million Btu/hr/CT firing natural gas and 1,900.2 million Btu/hr/CT firing fuel oil. The heat input ratings at 60°F for combined cycle operation are 1,751.1 million Btu/hr/CT firing natural gas and 1,896.3 million Btu/hr/CT firing fuel oil. During natural gas-fired combined cycle operations, natural gas-fired duct burners can supply an additional 332 million Btu/hr/HRSG at 60°F. The duct burners will not operate during fuel oil-fired combined cycle operations.

The CT units are equipped with evaporative cooling systems. Evaporative cooling involves wetting of cooling media with water which cools the inlet air when ambient temperatures are high. This improves the output and heat rate (efficiency) of the units and reduces the nitrogen oxides (NO_X) produced per unit of heat input. The CT units are equipped with dry low-NO_X combustors for natural gas firing and wet injection for fuel oil firing to reduce NO_X. During combined cycle operations, selective catalytic reduction (SCR) systems using aqueous ammonia as a reducing agent control emissions of NO_X. Sulfur dioxide (SO_2) emissions are controlled by the use of pipeline quality natural gas and low-sulfur No. 2 fuel oil. Good combustion practices and clean fuels also minimize potential emissions of particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOC), and other pollutants (e.g., trace metals). The CT units are also equipped with a CO catalyst to control CO and VOC emissions during combined cycle operations. For simple cycle operation, each CT discharges to the atmosphere through its own stack. For combined cycle operation, each CT/HRSG discharges to the atmosphere through its own stack. The six stacks (emission points) are considered significant emission sources.

OPERATIONAL AND CALCULATIONAL METHODOLOGY

Calculation of Heat Input

Generation capacity and heat rates in the JCC General Electric Model 7FA CT units vary with ambient temperature, fuel, and operational configuration. The CT units may be fired with natural gas (NG) or distillate oil, and with either fuel may be configured for simple-cycle (SC) or combined-cycle (CC) operation. In SC operation, the flue gas is routed directly to the CT generator (CTG) stack without heat recovery. In CC operation, CT flue gas is routed through the heat recovery steam generator (HRSG). Heat input to each HRSG may be supplemented by firing NG in its duct burners (DB).

Heat inputs (in 10^6 Btu [HHV]/CT-hr) for JCC CT units fired with either fuel in SC configuration are listed in Table 3-1. These were estimated by multiplying the gross generation output capacity (in megawatts [MW]/CT) times the corresponding gross heat rate (in Btu [HHV]/kW-hr).

$$Heat\ Input\left[10^6\frac{Btu}{CT-hr}\right] = Generation\left[\frac{MW}{CT}\right]\times 1000\,\frac{kW}{MW}\times Heat\ Rate\left[\frac{Btu}{kW-hr}\right]\times\frac{1}{10^6}$$

Table 3-1. JCC Nominal Simple-Cycle CT-Unit Generation, Heat Rates, and Heat Inputs

Ambient Temperature, degree F	Gross Generation Output, MW/CT		Gross Heat Rate, Btu [HHV]/kW-hr		Heat Input, 10^6 Btu [HHV]/CT-hr	
	NG	Oil	NG	Oil	NG	Oil
-5	196.69	196.79	9822	10,051	1931.9	1977.9
59	176.99	187.19	9921	10,151	1755.9	1900.2
102	166.44	179.07	10,072	10,196	1676.4	1825.8

Dual-fuel heat inputs for JCC CT units fired in CC configuration are listed in Table 3-2. No DB heat inputs will occur during oil-fired CC operations.

Table 3-2. JCC Nominal Combined-Cycle CT-Unit Generation, Heat Rates, and Heat Inputs								
Ambient Temperature, degree F	Gross CTG Generation Output, MW/CT		Gross CTG Heat Rate, Btu [HHV]/kW-hr		Heat Input, 10^6 Btu [HHV]/CT-hr			
					CTG		DB	
	NG	Oil	NG	Oil	NG	Oil	NG	Oil
-5	195.84	196.75	9858	10,103	1930.5	1987.8	347.5	0
60	174.54	186.79	10,033	10,152	1751.1	1896.3	332.0	0
102	164.73	177.25	10,185	10,303	1677.8	1826.2	345.3	0

In both Tables 3-1 and 3-2, operation parameters at 102 degree F ambient temperature reflect 85% evaporative cooler efficiency.

Calculation of Criteria-Pollutant and Non-HAP Emission Rates

Emission rates vary with ambient temperature, fuel, operational configuration, and control-equipment status. Maximum dual-fuel short-term emission estimates (in lb/CT-hr) for routine operations at full capacity in SC configuration are presented in Table 3-3. Estimates are listed for nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO_2), filterable particulate matter (PM_{fil}), and sulfur trioxide (SO_3)/sulfuric acid (H_2SO_4) expressed as H_2SO_4. Corresponding values for CC operations without and with DB firing are given in Tables 3-4 and 3-5.

Table 3-3. JCC Max Short-Term Routine-Operation SC CTG Emission Estimates, lb/CT-hr												
Ambient Temp., deg. F	NO_X		CO		VOC		SO_2		PM_{fil}		H_2SO_4	
	NG	Oil	NG	Oil	NG	Oil	NG	Oil	NG	Oil	NG	Oil
-5	84.1	325	51.2	94.3	3.42	8.10	1.05	94.9	6.62	17.9	0.084	7.65
59	76.4	313	46.5	90.7	3.11	7.79	0.951	91.2	6.62	17.9	0.077	7.35
102	72.9	301	44.4	87.2	2.97	7.49	0.908	87.6	6.62	17.9	0.073	7.06

Table 3-4. JCC Max Short-Term Routine-Operation CC (w/o DB) HRSG Emission Estimates, lb/CT-hr												
Ambient Temp., deg. F	NO_X		CO		VOC		SO_2		PM_{fil}		H_2SO_4	
	NG	Oil	NG	Oil	NG	Oil	NG	Oil	NG	Oil	NG	Oil
-5	21.0	156	12.8	47.4	3.66	10.9	0.938	85.5	6.95	48.5	0.249	22.7
60	19.0	149	11.6	45.2	3.32	10.4	0.851	81.6	6.92	47.1	0.226	21.7
102	18.3	143	11.1	43.6	3.18	9.99	0.815	78.6	6.91	46.0	0.217	20.9

Table 3-5. JCC Max Short-Term Routine-Operation CC (w/ DB) HRSG Emission Estimates, lb/CT-hr												
Ambient Temp., deg. F	NO_X		CO		VOC		SO_2		PM_{fil}		H_2SO_4	
	NG	Oil	NG	Oil	NG	Oil	NG	Oil	NG	Oil	NG	Oil
-5	24.8	-	15.1	-	10.1	-	0.974	-	9.84	-	0.497	-
60	22.6	-	13.8	-	9.21	-	0.891	-	9.78	-	0.454	-
102	22.0	-	13.4	-	8.94	-	0.865	-	9.76	-	0.441	-

Filterable particulate-matter (PM_{fil}) emission rates are presumed to equal the emissions of filterable PM less than 10 microns in diameter ($PM_{10\text{-}fil}$) as well as filterable PM less than 2.5 microns ($PM_{2.5\text{-}fil}$). This is based on AP-42 characterization of particle-size distributions for PM emissions from NG-fired and oil-fired CT units and boilers.

Input parameters used to derive emission estimates for the SC configuration while firing either NG or oil at 59 degrees F ambient temperature are presented in Table 3-6. Tables 3-7 and 3-8 contain corresponding dual-fuel input parameters for the CC configuration (without and with DB firing) at 60 degrees F ambient temperature.

Table 3-6. Inputs for JCC AY 2012 Emission Estimates for 59-deg-F SC Configuration		
Parameter	**Value**	**Units**
Actual NG usage AY 2012	320.44	MMscf/year
Actual oil usage AY 2012	0	gallon/year
NG heat content	1,020	Btu [HHV]/standard cubic foot (scf)
NG S content	2,000	grains sulfur/MMscf
Maximum NG S content	4,000	grains sulfur/MMscf
Actual oil heat content	137,817	Btu [HHV]/gallon
Actual oil S content	0.00226	percent (%) by weight
Maximum oil S content	0.05	percent (%) by weight
NO_X max CTG conc. NG	12	ppm by volume dry-basis (ppmvd) at 15% O_2
NO_X max CTG conc. oil	42	ppmvd at 15% O_2
CO max CTG conc. NG	12	ppmvd at 15% O_2
CO max CTG conc. oil	20	ppmvd at 15% O_2
VOC max CTG conc. NG	1.4	ppmvd at 15% O_2
VOC max CTG conc. oil	3.0	ppmvd at 15% O_2
PM_{fil} design CTG emssn. NG	9.0	lb/CT-hr
PM_{fil} design CTG emssn. oil	17.0	lb/CT-hr
PM_{fil} emssn. factor NG adjustment	30.0	%
PM vendor margin NG	5.0	%
PM vendor margin oil	5.0	%
CTG S to SO_3 NG	5.0	%
CTG S to SO_3 oil	5.0	%
CTG SC heat input NG	1,755.9	MMBtu [HHV]/CT-hr
CTG SC heat input oil	1,900.2	MMBtu [HHV]/CT-hr

In the SC configuration, flue gas bypasses the HRSG and exits to the atmosphere directly through the separate CTG stack. Since the selective-catalytic-reduction (SCR) reactor is in the HRSG flow path, no ammonia is input to the CT unit during SC operations. Consequently, SO_3/H_2SO_4 emissions are released without neutralization. Condensable particulate matter (PM_{cond}) is based on 5% of the volatile organic compounds plus the sulfuric acid emissions. Carbon dioxide equivalent emissions are based on methods from 40 CFR Part 98.

Table 3-7 contains dual-fuel input parameters used to estimate emissions for the combined-cycle (CC) configuration without duct-burner (DB) firing at 60-degrees-F ambient temperature.

Table 3-7. Inputs for JCC AY 2012 Emission Estimates for 60-deg-F CC Configuration (without DB)		
Parameter	**Value**	**Units**
Actual NG usage AY 2012	4,657.83	MMscf/year
Actual oil usage AY 2012	81.7	gallon/year
NG heat content	1,020	Btu [HHV]/standard cubic foot (scf)
NG S content	2,000	grains sulfur/MMscf
Maximum NG S content	4,000	grains sulfur/MMscf
Actual oil heat content	137,817	Btu [HHV]/gallon
Actual oil S content	0.00226	percent (%) by weight
NO_X max HRSG conc. NG	3.0	ppm by volume dry-basis (ppmvd) at 15% O_2
NO_X max HRSG conc. oil	20	ppmvd at 15% O_2
CO max HRSG conc. NG	3.0	ppmvd at 15% O_2
CO max HRSG conc. oil	10	ppmvd at 15% O_2
VOC max HRSG conc. NG DB off	1.5	ppmvd at 15% O_2
VOC max HRSG conc. oil	4.0	ppmvd at 15% O_2
PM_{fil} design CTG emssn. NG	9.0	lb/CT-hr
PM_{fil} design CTG emssn. oil	17.0	lb/CT-hr
PM_{fil} emssn. factor NG adjustment	30.0	%
PM vendor margin NG	5.0	%
PM vendor margin oil	5.0	%
CTG S to SO_3 NG	5.0	%
CTG S to SO_3 oil	5.0	%

Table 3-7. Inputs for JCC AY 2012 Emission Estimates for 60-deg-F CC Configuration (without DB)		
Parameter	**Value**	**Units**
SCR S to SO_3 NG	2.5	%
SCR S to SO_3 oil	2.5	%
CO cat S to SO_3 NG DB off	8.0	%
CO cat S to SO_3 oil	8.0	%
CTG CC heat input NG	1751.1	MMBtu [HHV]/CT-hr
CTG CC heat input oil	1896.3	MMBtu [HHV]/CT-hr

Table 3-8 contains dual-fuel input parameters used to estimate emissions for the combined-cycle (CC) configuration with duct-burner (DB) firing at 60-degrees-F ambient temperature.

Table 3-8. Inputs for JCC AY 2012 Emission Estimates for 60-deg-F CC Configuration (with DB)		
Parameter	**Value**	**Units**
Actual NG usage AY 2012	1,213.15	MMscf/year
NG heat content	1,020	Btu [HHV]/standard cubic foot (scf)
NG S content	2,000	grains sulfur/MMscf
Maximum NG S content	4,000	grains sulfur/MMscf
NO_X max HRSG conc. NG	3.0	ppm by volume dry-basis (ppmvd) at 15% O_2
CO max HRSG conc. NG	3.0	ppmvd at 15% O_2
VOC max HRSG conc. NG DB off	3.5	ppmvd at 15% O_2
PM_{fil} design CTG emssn. NG	9.0	lb/CT-hr
PM_{fil} emssn. factor NG adjustment	30.0	%
PM vendor margin NG	5.0	%
CTG S to SO_3 NG	5.0	%
SCR S to SO_3 NG	2.5	%
CO cat S to SO_3 NG DB off	19.0	%
CTG CC heat input NG	1751.1	MMBtu [HHV]/CT-hr
DB CC heat input NG	332	MMBtu [HHV]/CT-hr
DB PM_{fil} emission factor	0.01	lb/MMBtu [HHV]

For CC-configuration stack-exit temperatures (<350°F) in these CT units, H_2SO_4 is expected to fully react with any NH_3 that has penetrated the SCR reactor (NH_3 slip). If NH_3 is present in excess of double the H_2SO_4 concentration, the neutralization reaction will proceed to completion to form ammonium sulfate (AS). The NG-fired maximum stack-exit H_2SO_4 flue-gas concentration is predicted to be < 0.1 ppmvd at 15% O_2, and design NH_3 slip is expected to exceed the H_2SO_4 concentration by more than an order of magnitude. The oil-fired maximum stack-exit H_2SO_4 flue-gas concentration is predicted to be < 1.5 ppmvd at 15% O_2, and design NH_3 slip is expected to be more than double that value. Consequently the H_2SO_4 produced in the CT and catalyst beds is expected to be fully neutralized to form AS whenever NH_3 is being input to the SCR reactor. AS is a solid under Method 5 filterable-PM test conditions, so its emissions are included in the filterable-PM loadings listed in Tables 3-4 and 3-5. Condensable particulate matter (PM_{cond}) is based on 5% of the volatile organic compounds plus the sulfuric acid emissions. Carbon dioxide equivalent emissions are based on methods from 40 CFR Part 98.

Startup (SU) and shutdown (SD) emissions are significantly greater for some pollutants than those under routine operations, as indicated in Table 3-9.

Table 3-9. JCC CT/HRSG Startup/Shutdown Emission Estimates, lb/SU-SD										
Type of Operation	CT Unit		Fuel	NO_X	CO	VOC	SO_2	PM_{fil}	PM_{cond}	H_2SO_4
	Status	No.								
Hot SU	Lead	1	NG	109.3	906.6	152.5	0.2262	7.054	7.683	0.06008
			Oil	242.4	811.5	119.5	1.309	18.38	6.322	0.3478
	Lag	2	NG	67.12	805.8	134.1	0.1277	4.366	6.738	0.03392
			Oil	109.3	775.5	117.2	0.5025	6.820	5.994	0.1335
Warm SU	Lead	1	NG	222.1	1148.7	222.2	0.4992	18.26	11.24	0.1326
			Oil	400.8	1628.7	141.0	2.864	49.79	7.809	0.7607
	Lag	2	NG	110.1	909.8	153.2	0.2282	7.107	7.722	0.06062
			Oil	207.3	783.1	118.2	0.9548	12.27	6.162	0.2536
Cold SU	Lead	1	NG	415.9	1759.8	277.3	0.9975	38.46	14.13	0.2650
			Oil	575.5	2998.8	172.4	4.336	79.59	9.770	1.152
	Lag	2	NG	168.2	1048.5	178.6	0.3638	10.82	9.028	0.09665
			Oil	338.1	793.3	119.4	1.558	19.53	6.386	0.4138
SD		3	NG	15.51	22.00	5.616	0.1349	2.370	0.3166	0.03584
			Oil	39.88	12.79	1.041	0.5515	4.477	0.1985	0.1465

The number of startups by unit and type are shown in Table 3-10.

Table 3-10. AY 2012 JCC CT/HRSG Startups by Unit and Type								
Type	Natural Gas Fired				Oil Fired			
Unit #	CT1	CT2	CT3	JCC Total	CT1	CT2	CT3	JCC Total
Hot SU	10	7	6	23	0	0	0	0
Warm SU	0	0	1	1	0	0	0	0
Cold SU	1	1	1	3	0	0	0	0
SD	11	8	8	27	0	0	0	0

Emission Estimates for Hazardous Air Pollutants (HAP)

EPRI's Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants (EPRI Report No. 1005402, April 2002) lists HAP emission factors for uncontrolled boilers burning natural gas. While EPRI cautioned that these HAP emission factors are not appropriate for gas turbines, the trace-element HAP emission factors should be reasonably applicable since trace-element emissions (on the basis of mass per unit energy input) are directly related to the fuel composition whether burned in a boiler or a turbine.
No NG-fired emission factor for antimony (Sb) was listed in the EPRI data. An Sb emission factor for NG firing in a rotary kiln incinerator simulator (EPA-600/R-97-115, October 1997) was used to estimate Sb emissions. Oil-fired trace-element HAP emissions were generally estimated using AP-42 emission factors, but hydrogen chloride (HCl) and manganese (Mn) estimates reflect TVA CT oil specifications.

Emission factors used to estimate JCC trace-element HAP emissions are listed in Table 3-11. Mercury (Hg), selenium (Se), and HCl are considered to be emitted predominately in the gaseous phase and are considered non-VOC gaseous HAP. Other trace-element HAP constituents are considered to be emitted predominately as particulate matter (PM).

Table 3-11. CT Trace-Element HAP Emission Factors, lb/10^{12} Btu											
Fuel	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	HCl
NG	0.18	0.23	<0.01	0.04	1.1	0.08	0.4	0.4	0.0008	2.4	<0.02	-
Oil	22	11	0.31	4.8	11	9.1	14	101	1.2	4.6	25	311

TVA generally estimated JCC CT organic-HAP emissions using emission factors listed in AP-42 Section 3.1, "Stationary Gas Turbines" (5^{th} Edition, Supplement F, April 2000). TVA derived a site-specific NG-fired CT formaldehyde (CH_2O) emission factor from the AP-42 database (see discussion below).

TVA derived an NG-fired CT formaldehyde (CH_2O) emission factor using data downloaded from EPA's Combustion Turbine Database (documenting the AP-42 emission factor). This database lists CH_2O emission factors for tests from 22 NG-fired CT units operating at 80 to 110 percent load with no HAP controls. The average emission factor from the data set is 7.09E-04 lb/10^6 Btu and the coefficient of variation is 206 percent. The large variation reflects the wide variety of CT units in the database. Consequently, the emission factor may not be representative of the CT units proposed for this project. For example, nine of the units have ratings less than 15 MW and five are aircraft-derivative units. Of the eight remaining units, six are large frame-type CTs made by General Electric (GE) that TVA considers to be more nearly representative of its proposed units. Table 3-12 contains model number, rating, load condition, and emission factor for those six units.

Table 3-12. CH_2O Measurements for GE NG-Fired CT Units with Ratings > 40 MW				
Model	**Rating (MW)**	**Load (%)**	**Emission Factor ($lb/10^6$ Btu)**	**Count of Runs**
Frame 6	42.5	100	5.72E-05	3
Frame 7	75	100	8.42E-05	3
Frame 7B	50	100	1.32E-04	2
MS6000	44	100	1.08E-04	3
MS7001EA	87.83	100	6.70E-06	3
NS5000P	46.3	100	2.94E-04	3

The average emission factor from these six units is 1.14E-04 $lb/10^6$ Btu. The coefficient of variation is 86.5 percent. In view of this residual variability, TVA incorporated a margin of safety by using the factor 1.35E-04 $lb/10^6$ Btu to estimate CH_2O emissions. Based on similar considerations, TVA estimated oil-fired CH_2O emissions using an adjusted AP-42 emission factor, 230 $lb/10^{12}$ Btu.

Emission factors used to estimate JCC organic-HAP emissions are listed in Table 3-13.

Table 3-13. CT Organic HAP Emission Factors			
Pollutant	**CAS Number**	**CT Emission Factor $lb/10^{12}$ Btu**	
		NG	**Oil**
1,3-Butadiene	106-99-0	0.43	16
Acetaldehyde	75-07-0	40	-
Acrolein	107-02-8	6.4	-
Benzene	71-43-2	12	55
Ethyl Benzene	100-41-4	32	-
Formaldehyde	50-00-0	135	230
Naphthalene	91-20-3	1.3	35
Propylene Oxide	75-56-9	29	-
Toluene	108-88-3	130	-
Xylenes	1330-20-7	64	-
Polycyclic Organic Matter (POM)	-	2.2	40
VOC HAP Total	-	452.33	376

DATA AND SAMPLE EMISSION CALCULATIONS

Simple Cycle Operation for AY 2012

Actual emissions were determined from the actual natural gas and fuel oil usage in the combustion turbines, heat inputs of combustion turbines, nominal heat content of natural gas and fuel oil, and emission factors for each pollutant. Emission factors are shown in Tables 3-14 and 3-17. Emissions are tabulated in Table 3-18 for simple cycle operation. Data inputs are shown in Table 3-6 and below.

AY 2012 Natural Gas Usage for Simple Cycle, MMscf/year	320.44
AY 2012 Fuel Oil Usage for Simple Cycle, gal/year	0
Heat Input at 59°F for Natural Gas, MMBtu/hr	1,755.9
Heat Input at 59°F for Fuel Oil, MMBtu/hr	1,900.2
Natural Gas Nominal Heat Content, Btu/scf	1,020
Fuel Oil Heat Content, Btu/gal	137,817
Fuel Oil S Content, %	0.00226
PM_{fil} Design CTG Emissions NG, lb/hr	9
PM_{fil} Design CTG Emissions Oil, lb/hr	17
PM_{fil} Emission Factor NG Adjustment, %	30
PM Vendor Margin for NG and Oil, %	5
CTG S to SO_3 for NG and Oil, %	5

Filterable Particulates

PM emission rate for natural gas is 6.3 lb/hr based on design of 9 lb/hr and 30% adjustment based on vendor information (9 x 0.7 = 6.3) from Table 3-6.

$$\text{PM Emission Factor} = \frac{6.3 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}755.9 \text{ MMBtu}} = \frac{3.59\text{E}-03 \text{ lb}}{\text{MMBtu}}$$

PM emission rate for fuel oil is 17 lb/hr from Table 3-6, based on design of 17 lb/hr.

$$\text{PM Emission Factor} = \frac{17 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}900.2 \text{ MMBtu}} = \frac{8.95\text{E}-03 \text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions

For maximum hourly emissions the vendor has a 5% margin for both natural gas and fuel oil.

For natural gas 6.3 lb/hr x 1.05 = 6.62 lb/hr

For fuel oil 17 lb/hr x 1.05 = 17.9 lb/hr

Actual annual emissions

$$\text{For natural gas } \frac{3.59\text{E}-03 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{320.44 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 0.586 \text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

Condensable Particulates

Emission Factors are determined by adding 5% of the VOC emission factor to the sulfuric acid emission factor.

For natural gas

$$\text{PM}_{\text{cond}} \text{ Emission Factor} = \frac{1.77\text{E}-03 \text{ lb}}{\text{MMBtu}} \text{ x } 0.05 + \frac{4.59\text{E}-05 \text{ lb}}{\text{MMBtu}} = \frac{1.34\text{E}-04 \text{ lb}}{\text{MMBtu}}$$

For fuel oil

$$\text{PM}_{\text{cond}} \text{ Emission Factor} = \frac{4.10\text{E}-03 \text{ lb}}{\text{MMBtu}} \text{ x } 0.05 + \frac{1.75\text{E}-04 \text{ lb}}{\text{MMBtu}} = \frac{3.80\text{E}-04 \text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions are determined by adding 5% of the VOC maximum hourly emissions to the sulfuric acid maximum hourly emissions and applying the 5% extra margin based on PM vendor margin.

For natural gas (3.42 lb/hr x 0.05 + 0.0887 lb/hr) x 1.05 = 0.273 lb/hr

For fuel oil (8.11 lb/hr x 0.05 + 7.65) x 1.05 = 8.45 lb/hr

Actual annual emissions are determined by adding 5% of the VOC emissions to the sulfuric acid emissions.

For natural gas 0.289 tons/year x 0.05 + 0.00751 lb/hr = 0.0220 tons/year

There was no fuel oil burned during simple cycle operation.

Nitrogen Oxides

NO_X emission rate for natural gas is 76.4 lb/hr from Table 3-3.

$$NO_X \text{ Emission Factor} = \frac{76.4 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}755.9 \text{ MMBtu}} = \frac{4.35\text{E}-02 \text{ lb}}{\text{MMBtu}}$$

NO_X emission rate for fuel oil is 313 lb/hr from Table 3-3.

$$NO_X \text{ Emission Factor} = \frac{313 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}900.2 \text{ MMBtu}} = \frac{1.65\text{E}-01 \text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for fuel oil (from Table 3-1).

$$\text{For natural gas } \frac{4.35\text{E}-02 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}931.9 \text{ MMBtu}}{\text{hr}} = 84.1 \text{ lb/hr}$$

$$\text{For fuel oil } \frac{1.65\text{E}-01 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}977.9 \text{ MMBtu}}{\text{hr}} = 326 \text{ lb/hr}$$

Actual annual emissions

Annual emissions for natural gas are based on CEMS measurement of 6.05 tons/year

There was no fuel oil burned during simple cycle operation.

Carbon Monoxide

CO emission rate for natural gas is 46.5 lb/hr from Table 3-3.

$$\text{CO Emission Factor} = \frac{46.5 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}755.9 \text{ MMBtu}} = \frac{2.65\text{E}-02 \text{ lb}}{\text{MMBtu}}$$

CO emission rate for fuel oil is 90.7 lb/hr from Table 3-3.

$$\text{CO Emission Factor} = \frac{90.7 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}900.2 \text{ MMBtu}} = \frac{4.77\text{E}-02 \text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for fuel oil (from Table 3-1).

$$\text{For natural gas } \frac{2.65\text{E}-02 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}931.9 \text{ MMBtu}}{\text{hr}} = 51.2 \text{ lb/hr}$$

$$\text{For fuel oil } \frac{4.77\text{E}-02 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}977.9 \text{ MMBtu}}{\text{hr}} = 94.4 \text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas } \frac{2.65\text{E}-02 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{320.44 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 4.33 \text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

Volatile Organic Compounds

VOC emission rate for natural gas is 3.11 lb/hr from Table 3-3.

$$\text{VOC Emission Factor} = \frac{3.11 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}755.9 \text{ MMBtu}} = \frac{1.77\text{E}-03 \text{ lb}}{\text{MMBtu}}$$

VOC emission rate for fuel oil is 7.79 lb/hr from Table 3-3.

$$\text{VOC Emission Factor} = \frac{7.79\text{ lb}}{\text{hr}}\text{ x }\frac{\text{hr}}{1{,}900.2\text{ MMBtu}} = \frac{4.10\text{E}-03\text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for fuel oil (from Table 3-1).

$$\text{For natural gas }\frac{1.77\text{E}-03\text{ lb}}{\text{MMBtu}}\text{ x }\frac{1{,}931.9\text{ MMBtu}}{\text{hr}} = 3.42\text{ lb/hr}$$

$$\text{For fuel oil }\frac{4.10\text{E}-03\text{ lb}}{\text{MMBtu}}\text{ x }\frac{1{,}977.9\text{ MMBtu}}{\text{hr}} = 8.11\text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas }\frac{1.77\text{E}-03\text{ lb}}{\text{MMBtu}}\text{ x }\frac{1{,}020\text{ Btu}}{\text{scf}}\text{ x }\frac{320.44\text{ MMscf}}{\text{yr}}\text{ x }\frac{\text{ton}}{2{,}000\text{ lb}} = 0.289\text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

Sulfur Dioxide

Based on 2,000 grains of sulfur/MMscf for natural gas, the AP-42 emission factor of 0.0006 lb/MMBtu is reduced by 5% due to the conversion to SO_3.

$$SO_2\text{ Emission Factor} = \frac{0.0006\text{ lb}}{\text{MMBtu}}\text{ x }0.95 = 5.70\text{E}-04\text{ lb/MMBtu}$$

Based on 0.00226% fuel oil sulfur content, the AP-42 emission factor of 1.01 x 0.00226 lb/MMBtu is reduced by 5% due to the conversion to SO_3.

$$SO_2\text{ Emission Factor} = \frac{1.01\text{ x }0.00226\text{ lb}}{\text{MMBtu}}\text{ x }0.95 = \frac{2.17\text{E}-03\text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for uel oil (from Table 3-1). Maximum fuel oil sulfur content of 0.05% S.

$$\text{For natural gas }\frac{5.70\text{E}-04\text{ lb}}{\text{MMBtu}}\text{ x }\frac{1{,}931.9\text{ MMBtu}}{\text{hr}} = 1.10\text{ lb/hr}$$

$$\text{For fuel oil (0.05\% S) }\frac{1.01\text{ x }0.05\text{ x }0.95\text{ lb}}{\text{MMBtu}}\text{ x }\frac{1{,}977.9\text{ MMBtu}}{\text{hr}} = 94.9\text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas }\frac{5.70\text{E}-04\text{ lb}}{\text{MMBtu}}\text{ x }\frac{1{,}020\text{ Btu}}{\text{scf}}\text{ x }\frac{320.44\text{ MMscf}}{\text{yr}}\text{ x }\frac{\text{ton}}{2{,}000\text{ lb}} = 0.0932\text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

Sulfuric Acid

Based on 2,000 grains of sulfur/MMscf for natural gas, the AP-42 emission factor of 0.0006 lb/MMBtu for SO_2 is adjusted due to 5% conversion to SO_3 and then converted to sulfuric acid.

$$H_2SO_4 \text{ Emission Factor} = \frac{0.0006 \text{ lb}}{\text{MMBtu}} \text{ x } 0.05 \text{ x } \frac{98}{64} = 4.59\text{E}-05 \text{ lb/MMBtu}$$

Based on 0.00226% fuel oil sulfur content, the AP-42 emission factor of 1.01 x 0.00226 lb/MMBtu for SO_2 is adjusted due to 5% conversion to SO_3 and then converted to sulfuric acid.

$$H_2SO_4 \text{ Emission Factor} = \frac{1.01 \text{ x } 0.00226 \text{ lb}}{\text{MMBtu}} \text{ x } 0.05 \text{ x } \frac{98}{64} = \frac{1.75\text{E}-04 \text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for fuel oil (from Table 3-1). Maximum fuel oil sulfur content of 0.05% S.

$$\text{For natural gas } \frac{4.59\text{E}-05 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}931.9 \text{ MMBtu}}{\text{hr}} = 0.0887 \text{ lb/hr}$$

$$\text{For fuel oil (0.05\% S) } \frac{1.01 \text{ x } 0.05 \text{ x } 0.05 \text{ x } 98/64 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}977.9 \text{ MMBtu}}{\text{hr}} = 7.65 \text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas } \frac{4.59\text{E}-05 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{320.44 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 0.00751 \text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

Carbon Dioxide Equivalent

For natural gas, carbon dioxide equivalent emission factor was determined from 40 CFR Part 98 using the following equation.

$$\left[\frac{53.02 \text{ kg } CO_2}{\text{MMBtu}} + \frac{0.001 \text{ kg } CH_4}{\text{MMBtu}} \text{ x } \frac{21 \text{ kg } CO_2}{\text{kg } CH_4} + \frac{0.0001 \text{ kg } N_2O}{\text{MMBtu}} \text{ x } \frac{310 \text{ kg } CO_2}{\text{kg } N_2O}\right]$$

$$\text{x } \frac{2.20462 \text{ lb}}{1 \text{ kg}} = 117 \frac{\text{lb } CO_2 \text{ equiv}}{\text{MMBtu}}$$

For fuel oil, carbon dioxide equivalent emission factor was determined from 40 CFR Part 98 using the following equation.

$$\left[\frac{73.96 \text{ kg } CO_2}{\text{MMBtu}} + \frac{0.003 \text{ kg } CH_4}{\text{MMBtu}} \text{ x } \frac{21 \text{ kg } CO_2}{\text{kg } CH_4} + \frac{0.0006 \text{ kg } N_2O}{\text{MMBtu}} \text{ x } \frac{310 \text{ kg } CO_2}{\text{kg } N_2O}\right]$$

$$\text{x } \frac{2.20462 \text{ lb}}{1 \text{ kg}} = 164 \frac{\text{lb } CO_2 \text{ equiv}}{\text{MMBtu}}$$

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for fuel oil (from Table 3-1).

$$\text{For natural gas } \frac{117 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}931.9 \text{ MMBtu}}{\text{hr}} = 226{,}039 \text{ lb/hr}$$

$$\text{For fuel oil } \frac{164 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}977.9 \text{ MMBtu}}{\text{hr}} = 323{,}590 \text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas } \frac{117 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{320.44 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 19{,}921 \text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

Antimony

Antimony emission factor for natural gas is 1.80E-07 lb/MMBtu from Table 3-17.

Antimony emission factor for fuel oil is 2.20E-05 lb/MMBtu from Table 3-17.

Maximum hourly emissions

Maximum heat input at -5°F is 1,931.9 MMBtu/hr for natural gas and 1,977.9 MMBtu/hr for fuel oil (from Table 3-1).

$$\text{For natural gas } \frac{1.80\text{E} - 07 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}931.9 \text{ MMBtu}}{\text{hr}} = 3.48\text{E} - 04 \text{ lb/hr}$$

$$\text{For fuel oil } \frac{2.20\text{E} - 05 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}977.9 \text{ MMBtu}}{\text{hr}} = 4.35\text{E} - 02 \text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas } \frac{1.80\text{E} - 07 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{320.44 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}}$$

$$= 2.94\text{E} - 05 \text{ tons/year}$$

There was no fuel oil burned during simple cycle operation.

The remaining HAPs are determined the same as they were for antimony.

Combined Cycle Operation without Duct Burners for AY 2012

Actual emissions were determined from the actual natural gas and fuel oil usage in the combustion turbines, heat inputs of combustion turbines, nominal heat content of natural gas and fuel oil, and emission factors for each pollutant. Emission factors are shown in Tables 3-15 and 3-17. Emissions are tabulated in Table 3-19 for combined cycle operation without duct burners. Data inputs are shown in Table 3-7 and below.

AY 2012 Natural Gas Usage for Combined Cycle w/o DB, MMscf/year	4,657.83
AY 2012 Fuel Oil Usage for Combined Cycle w/o DB, gal/year	81.7
Heat Input at 60°F for Natural Gas, MMBtu/hr	1,751.1
Heat Input at 60°F for Fuel Oil, MMBtu/hr	1,896.3
Natural Gas Nominal Heat Content, Btu/scf	1,020
Fuel Oil Heat Content, Btu/gal	137,817
Fuel Oil S Content, %	0.00226
PM_{fil} Design CTG Emissions NG, lb/hr	9
PM_{fil} Design CTG Emissions Oil, lb/hr	17
PM_{fil} Emission Factor NG Adjustment, %	30
PM Vendor Margin for NG and Oil, %	5
CTG S to SO_3 for NG and Oil, %	5
SCR S to SO_3 for NG and Oil, %	2.5
CO Catalyst S to SO_3 for NG and Oil, %	8

Filterable Particulates

PM emission rate for natural gas is 6.3 lb/hr based on design of 9 lb/hr and 30% adjustment based on vendor information (9 x 0.7 = 6.3) from Table 3-7.

$$\text{PM Emission Factor} = \frac{6.3\text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}751.1\text{ MMBtu}} = \frac{3.60\text{E}-03\text{ lb}}{\text{MMBtu}}$$

PM emission rate for fuel oil is 17 lb/hr from Table 3-7, based on design of 17 lb/hr.

$$\text{PM Emission Factor} = \frac{17\text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}896.3\text{ MMBtu}} = \frac{8.96\text{E}-03\text{ lb}}{\text{MMBtu}}$$

Max Hourly emissions:

For maximum hourly emissions the vendor has a 5% margin for both natural gas and fuel oil. Also all of the sulfuric acid will be converted to ammonium sulfate particulate.

For natural gas 6.3 lb/hr x 1.05 + 0.262 lb H_2SO_4/hr x 132/98 = 6.97 lb/hr

For fuel oil 17 lb/hr x 1.05 + 22.7 x 132/98 = 48.5 lb/hr

Actual annual emissions :

For annual emissions, it is assumed that 99% of the sulfuric acid is converted to ammonium sulfate particulate due to ammonia being fed to the SCR about 99% of the operating time.

$$\text{For natural gas } \frac{3.60\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}}$$

$$+ \frac{1.36\text{E}-04\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83\text{ MMscf}}{\text{yr}} \text{ x } 0.99 \text{ x } \frac{132}{98} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 8.98\text{ tons/year}$$

$$\text{For fuel oil } \frac{8.96\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817\text{ Btu}}{\text{gal}} \text{ x } \frac{81.7\text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}}$$

$$+ \frac{5.17\text{E}-04\text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817\text{ Btu}}{\text{gal}} \text{ x } \frac{81.7\text{ gal}}{\text{yr}} \text{ x } 0.99 \text{ x } \frac{132}{98} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 5.44\text{E}-05\text{ tons/year}$$

Total actual annual emissions = 8.98 tons/year + 5.44E-05 tons/year = 8.98 tons/year

Condensable Particulates

Emission Factors are determined by adding 5% of the VOC emission factor to the sulfuric acid emission factor.

For natural gas

$$\text{PM}_{\text{cond}}\text{ Emission Factor} = \frac{1.90\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } 0.05 + \frac{1.36\text{E}-04\text{ lb}}{\text{MMBtu}} = \frac{2.31\text{E}-04\text{ lb}}{\text{MMBtu}}$$

For fuel oil

$$\text{PM}_{\text{cond}}\text{ Emission Factor} = \frac{5.48\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } 0.05 + \frac{5.17\text{E}-04\text{ lb}}{\text{MMBtu}} = \frac{7.92\text{E}-04\text{ lb}}{\text{MMBtu}}$$

Maximum hourly emissions are determined by adding 5% of the VOC maximum hourly emissions to the sulfuric acid maximum hourly emissions and applying the 5% extra margin based on PM vendor margin.

For natural gas (3.66 lb/hr x 0.05 + 0.262 lb/hr) x 1.05 = 0.467 lb/hr

For fuel oil (10.9 lb/hr x 0.05 + 22.7) x 1.05 = 24.4 lb/hr

Actual annual emissions are determined by adding 5% of the VOC emissions to the sulfuric acid emissions for both natural gas and fuel oil and adding the two for the total emissions.

For natural gas 4.50 tons/year x 0.05 + 0.00323 tons/year = 0.228 tons/year

For fuel oil 3.09E-05 tons/year x 0.05 + 2.91E-08 tons/year = 1.57E-06 tons/year

Total actual annual emissions = 0.228 tons/year + 1.57E-06 tons/year = 0.228 tons/year

Nitrogen Oxides

NO_X emission rate for natural gas is 19 lb/hr from Table 3-4.

$$\mathrm{NO_X\ Emission\ Factor} = \frac{19\ \mathrm{lb}}{\mathrm{hr}}\ \mathrm{x}\ \frac{\mathrm{hr}}{1{,}751.1\ \mathrm{MMBtu}} = \frac{1.09\mathrm{E}{-}02\ \mathrm{lb}}{\mathrm{MMBtu}}$$

NO_X emission rate for fuel oil is 149 lb/hr from Table 3-4.

$$\mathrm{NO_X\ Emission\ Factor} = \frac{149\ \mathrm{lb}}{\mathrm{hr}}\ \mathrm{x}\ \frac{\mathrm{hr}}{1{,}896.3\ \mathrm{MMBtu}} = \frac{7.86\mathrm{E}{-}02\ \mathrm{lb}}{\mathrm{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2).

$$\mathrm{For\ natural\ gas}\ \frac{1.09\mathrm{E}-02\ \mathrm{lb}}{\mathrm{MMBtu}}\ \mathrm{x}\ \frac{1{,}930.5\ \mathrm{MMBtu}}{\mathrm{hr}} = 21.0\ \mathrm{lb/hr}$$

$$\mathrm{For\ fuel\ oil}\ \frac{7.86\mathrm{E}-02\ \mathrm{lb}}{\mathrm{MMBtu}}\ \mathrm{x}\ \frac{1{,}987.8\ \mathrm{MMBtu}}{\mathrm{hr}} = 156\ \mathrm{lb/hr}$$

Actual annual emissions :

Annual emissions for natural gas and fuel oil are based on CEMs measurement of 33.4 tons/year for both without duct burners and with duct burners. Based on fuel type and quantities burned for both without and with DB, 26.5 tons/year of NO_X was emitted burning natural gas and 4.55E-04 tons/year of NO_X was emitted burning fuel oil without DB.

Total actual annual emissions = 26.5 tons/year + 4.55E-04 tons/year = 26.5 tons/year.

Carbon Monoxide

CO emission rate for natural gas is 11.6 lb/hr from Table 3-4.

$$\mathrm{CO\ Emission\ Factor} = \frac{11.6\ \mathrm{lb}}{\mathrm{hr}}\ \mathrm{x}\ \frac{\mathrm{hr}}{1{,}751.1\ \mathrm{MMBtu}} = \frac{6.62\mathrm{E}-03\ \mathrm{lb}}{\mathrm{MMBtu}}$$

CO emission rate for fuel oil is 45.2 lb/hr from Table 3-4.

$$\mathrm{CO\ Emission\ Factor} = \frac{45.2\ \mathrm{lb}}{\mathrm{hr}}\ \mathrm{x}\ \frac{\mathrm{hr}}{1{,}896.3\ \mathrm{MMBtu}} = \frac{2.38\mathrm{E}-02\ \mathrm{lb}}{\mathrm{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2).

$$\mathrm{For\ natural\ gas}\ \frac{6.62\mathrm{E}-03\ \mathrm{lb}}{\mathrm{MMBtu}}\ \mathrm{x}\ \frac{1{,}930.5\ \mathrm{MMBtu}}{\mathrm{hr}} = 12.8\ \mathrm{lb/hr}$$

$$\text{For fuel oil } \frac{2.38\text{E}-02\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}987.8\text{ MMBtu}}{\text{hr}} = 47.4\text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{6.62\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 15.7\text{ tons/year}$$

$$\text{For fuel oil } \frac{2.38\text{E}-02\text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817\text{ Btu}}{\text{gal}} \text{ x } \frac{81.7\text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 1.34\text{E}-04\text{ tons/year}$$

Total actual annual emissions = 15.7 tons/year + 1.34E-04 tons/year = 15.7 tons/year

Volatile Organic Compounds

VOC emission rate for natural gas is 3.32 lb/hr from Table 3-4.

$$\text{VOC Emission Factor} = \frac{3.32\text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}751.1\text{ MMBtu}} = \frac{1.90\text{E}-03\text{ lb}}{\text{MMBtu}}$$

VOC emission rate for fuel oil is 10.4 lb/hr from Table 3-4.

$$\text{VOC Emission Factor} = \frac{10.4\text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{1{,}896.3\text{ MMBtu}} = \frac{5.48\text{E}-03\text{ lb}}{\text{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2).

$$\text{For natural gas } \frac{1.90\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}930.5\text{ MMBtu}}{\text{hr}} = 3.66\text{ lb/hr}$$

$$\text{For fuel oil } \frac{5.48\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}987.8\text{ MMBtu}}{\text{hr}} = 10.9\text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{1.90\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 4.50\text{ tons/year}$$

$$\text{For fuel oil } \frac{5.48\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817\text{ Btu}}{\text{gal}} \text{ x } \frac{81.7\text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 3.09\text{E}-05\text{ tons/year}$$

Total actual annual emissions = 4.50 tons/year + 3.09E-05 tons/year = 4.50 tons/year

Sulfur Dioxide

Based on 2,000 grains of sulfur/MMscf for natural gas, the AP-42 emission factor of 0.0006 lb/MMBtu is reduced due to 5% conversion to SO_3 in the CTG, 2.5% in the SCR, and 8% in the CO catalyst.

$$SO_2\text{ Emission Factor} = \frac{0.0006\text{ lb}}{\text{MMBtu}} \text{ x } 0.95 \text{ x } 0.975 \text{ x } 0.92 = 5.11\text{E}-04\text{ lb/MMBtu}$$

Based on 0.00226% fuel oil sulfur content, the AP-42 emission factor of 1.01 x 0.00226 lb/MMBtu is reduced due to 5% conversion to SO_3 in the CTG, 2.5% in the SCR, and 8% in the CO catalyst.

$$SO_2\text{ Emission Factor} = \frac{1.01\text{ x }0.00226\text{ lb}}{\text{MMBtu}} \text{ x } 0.95 \text{ x } 0.975 \text{ x } 0.92 = \frac{1.95\text{E}-03\text{ lb}}{\text{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2). Maximum fuel oil sulfur content of 0.05% S.

$$\text{For natural gas } \frac{5.11\text{E}-04 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}930.5 \text{ MMBtu}}{\text{hr}} = 0.987 \text{ lb/hr}$$

$$\text{For fuel oil (0.05\% S) } \frac{1.01 \text{ x } 0.05 \text{ x } 0.95 \text{ x } 0.975 \text{ x } 0.92 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}987.8 \text{ MMBtu}}{\text{hr}} = 85.5 \text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{5.11\text{E}-04 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 1.21 \text{ tons/year}$$

$$\text{For fuel oil } \frac{1.95\text{E}-03 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817 \text{ Btu}}{\text{gal}} \text{ x } \frac{81.7 \text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 1.10\text{E}-05 \text{ tons/year}$$

Total actual annual emissions = 1.21 tons/year + 1.10E-05 tons/year = 1.21 tons/year

Sulfuric Acid

Based on 2,000 grains of sulfur/MMscf for natural gas, the AP-42 emission factor of 0.0006 lb/MMBtu for SO_2 is adjusted due to 5% conversion to SO_3 in the CTG, 2.5% in the SCR, and 8% in the CO catalyst and then converted to sulfuric acid.

$$H_2SO_4 \text{ Emission Factor} = \frac{0.0006 \text{ lb}}{\text{MMBtu}} \text{ x } (1 - 0.95 \text{ x } 0.975 \text{ x } 0.92) \text{ x } \frac{98}{64}$$

$$= 1.36\text{E}-04 \text{ lb/MMBtu}$$

Based on 0.00226% fuel oil sulfur content, the AP-42 emission factor of 1.01 x 0.00226 lb/MMBtu for SO_2 is adjusted due to 5% conversion to SO_3 in the CTG, 2.5% in the SCR, and 8% in the CO catalyst and then converted to sulfuric acid.

$$H_2SO_4 \text{ Emission Factor} = \frac{1.01 \text{ x } 0.00226 \text{ lb}}{\text{MMBtu}} \text{ x } (1 - 0.95 \text{ x } 0.975 \text{ x } 0.92) \text{ x } \frac{98}{64}$$

$$= 5.17\text{E}-04 \text{ lb/MMBtu}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2). Maximum fuel oil sulfur content of 0.05% S.

$$\text{For natural gas } \frac{1.36\text{E}-04 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}930.5 \text{ MMBtu}}{\text{hr}} = 0.262 \text{ lb/hr}$$

$$\text{For fuel oil (0.05\% S) } \frac{1.01 \text{ x } 0.05 \text{ x } (1 - 0.95 \text{ x } 0.975 \text{ x } 0.92) \text{ x } \frac{98}{64} \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}986.8 \text{ MMBtu}}{\text{hr}}$$

$$= 22.7 \text{ lb/hr}$$

Actual annual emissions :

For annual emissions, it is assumed that 99% of the sulfuric acid is converted to ammonium sulfate particulate due to ammonia being fed to the SCR about 99% of the operating time.

$$\text{For natural gas } \frac{1.36\text{E}-04 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} \text{ x } 0.01$$

$$= 0.00323 \text{ tons/year}$$

$$\text{For fuel oil } \frac{5.17\text{E}-04 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817 \text{ Btu}}{\text{gal}} \text{ x } \frac{81.7 \text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} \text{ x } 0.01 = 2.91\text{E}-08 \text{ tons/year}$$

Total actual annual emissions = 0.00323 tons/year + 2.91E-08 tons/year = 0.00323 tons/year

Carbon Dioxide

For natural gas, carbon dioxide equivalent emission factor was determined from 40 CFR Part 98 using the following equation.

$$\left[\frac{53.02 \text{ kg } CO_2}{\text{MMBtu}} + \frac{0.001 \text{ kg } CH_4}{\text{MMBtu}} \text{ x } \frac{21 \text{ kg } CO_2}{\text{kg } CH_4} + \frac{0.0001 \text{ kg } N_2O}{\text{MMBtu}} \text{ x } \frac{310 \text{ kg } CO_2}{\text{kg } N_2O}\right]$$

$$\text{x } \frac{2.20462 \text{ lb}}{1 \text{ kg}} = 117 \frac{\text{lb } CO_2 \text{ equiv}}{\text{MMBtu}}$$

For fuel oil, carbon dioxide equivalent emission factor was determined from 40 CFR Part 98 using the following equation.

$$\left[\frac{73.96 \text{ kg } CO_2}{\text{MMBtu}} + \frac{0.003 \text{ kg } CH_4}{\text{MMBtu}} \text{ x } \frac{21 \text{ kg } CO_2}{\text{kg } CH_4} + \frac{0.0006 \text{ kg } N_2O}{\text{MMBtu}} \text{ x } \frac{310 \text{ kg } CO_2}{\text{kg } N_2O}\right]$$

$$\text{x } \frac{2.20462 \text{ lb}}{1 \text{ kg}} = 164 \frac{\text{lb } CO_2 \text{ equiv}}{\text{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2).

$$\text{For natural gas } \frac{117 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}930.5 \text{ MMBtu}}{\text{hr}} = 225{,}875 \text{ lb/hr}$$

$$\text{For fuel oil } \frac{164 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}987.8 \text{ MMBtu}}{\text{hr}} = 325{,}209 \text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{117 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 277{,}941 \text{ tons/year}$$

$$\text{For fuel oil } \frac{164 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817 \text{ Btu}}{\text{gal}} \text{ x } \frac{81.7 \text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 0.921 \text{ tons/year}$$

Total actual annual emissions = 277,941 tons/year + 0.921 tons/year = 277,942 tons/year

Antimony

Antimony emission factor for natural gas is 1.80E-07 lb/MMBtu from Table 3-17.

Antimony emission factor for fuel oil is 2.20E-05 lb/MMBtu from Table 3-17.

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for natural gas and 1,987.8 MMBtu/hr for fuel oil (from Table 3-2).

$$\text{For natural gas } \frac{1.80\text{E}-07 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}930.5 \text{ MMBtu}}{\text{hr}} = 3.47\text{E}-04 \text{ lb/hr}$$

$$\text{For fuel oil } \frac{2.20\text{E}-05 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}987.8 \text{ MMBtu}}{\text{hr}} = 4.37\text{E}-02 \text{ lb/hr}$$

Annual emissions :

$$\text{For natural gas } \frac{1.80\text{E}-07 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{4{,}657.83 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}}$$

$$= 4.28\text{E}-04 \text{ tons/year}$$

$$\text{For fuel oil } \frac{2.20\text{E}-05 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{137{,}817 \text{ Btu}}{\text{gal}} \text{ x } \frac{81.7 \text{ gal}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 1.24\text{E}-07 \text{ tons/year}$$

Total annual emissions = 4.28E-04 tons/year + 1.24E-07 tons/year = 4.28E-04 tons/year

The remaining HAPs are determined the same as they were for antimony.

Combined Cycle Operation with Duct Burners for AY 2012

Actual emissions were determined from the actual natural gas usage in the combustion turbines and duct burners, heat inputs of combustion turbines and duct burners, nominal heat content of natural gas, and emission factors for each pollutant. Emission factors are shown in Tables 3-16 and 3-17. Emissions are tabulated in Table 3-20 for combined cycle operation with duct burners. Data inputs are shown in Table 3-8 and below.

AY 2012 Natural Gas Usage for Combined Cycle with DB, MMscf/year	1,213.15
Heat Input at 60°F for Natural Gas, MMBtu/hr	1,751.1
Heat Input at 60°F for Duct Burner, MMBtu/hr	332
Natural Gas Nominal Heat Content, Btu/scf	1,020
PM_{fil} Design CTG Emissions NG, lb/hr	9
PM_{fil} Emission Factor NG Adjustment, %	30
PM Vendor Margin for NG, %	5
Duct Burner PM_{fil} emission factor, lb/MMBtu	0.01
CTG S to SO_3 for NG, %	5
SCR S to SO_3 for NG, %	2.5
CO Catalyst S to SO_3 for NG, %	19

Filterable Particulates

PM emission rate for natural gas is 6.3 lb/hr based on design of 9 lb/hr and 30% adjustment based on vendor information (9 x 0.7 = 6.3) from Table 3-8. PM emission factor also includes the emissions from the duct burner based on 332 MMBtu/hr, emission factor of 0.01 lb/ MMBtu, and 30% reduction.

$$\text{PM Emission Factor} = \left(\frac{6.3 \text{ lb}}{\text{hr}} + \frac{332 \text{ MMBtu}}{\text{hr}} \text{ x } \frac{0.01 \text{ lb}}{\text{MMBtu}} \text{ x } 0.7\right) \text{ x } \frac{\text{hr}}{(1{,}751.1 + 332)\text{MMBtu}}$$

$$= \frac{4.14\text{E}-03 \text{ lb}}{\text{MMBtu}}$$

Max Hourly emissions:

For maximum hourly emissions the vendor has a 5% margin for natural gas. The maximum duct burner heat input at -5°F is 347.5 MMBtu/hr. Also all of the sulfuric acid will be converted to ammonium sulfate particulate.

For natural gas (6.3 lb/hr + 347.5 MMBtu/hr x 0.01 1b/MMBtu x 0.7) x 1.05 +

0.523 lb H_2SO_4/hr x 132/98 = 9.87 lb/hr

Actual annual emissions :

For annual emissions, it is assumed that 99% of the sulfuric acid is converted to ammonium sulfate particulate due to ammonia being fed to the SCR about 99% of the operating time.

$$\text{For natural gas } \frac{4.14\text{E}-03 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15 \text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}}$$

$$+\frac{2.29\text{E}-04 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020 \text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15 \text{ MMscf}}{\text{yr}} \text{ x } 0.99 \text{ x } \frac{132}{98} \text{ x } \frac{\text{ton}}{2{,}000 \text{ lb}} = 2.75 \text{ tons/year}$$

Condensable Particulates

Emission Factors are determined by adding 5% of the VOC emission factor to the sulfuric acid emission factor.

For natural gas
PM_{cond} Emission Factor $= \frac{4.42\text{E}-03 \text{ lb}}{\text{MMBtu}} \text{ x } 0.05 + \frac{2.29\text{E}-04 \text{ lb}}{\text{MMBtu}} = \frac{4.50\text{E}-04 \text{ lb}}{\text{MMBtu}}$

Maximum hourly emissions are determined by adding 5% of the VOC maximum hourly emissions to the sulfuric acid maximum hourly emissions and applying the 5% extra margin based on PM vendor margin.

For natural gas (10.1 lb/hr x 0.05 + 0.523 lb/hr) x 1.05 = 1.08 lb/hr

Actual annual emissions are determined by adding 5% of the VOC emissions to the sulfuric acid emissions.

For natural gas 2.74 tons/year x 0.05 + 0.00142 tons/year = 0.138 tons/year

Nitrogen Oxides

NO_X emission rate for natural gas is 22.6 lb/hr from Table 3-5.

NO_X Emission Factor $= \frac{22.6 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{(1{,}751.1+332) \text{ MMBtu}} = \frac{1.09\text{E}-02 \text{ lb}}{\text{MMBtu}}$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{1.09\text{E}-02 \text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{MMBtu}}{\text{hr}} = 24.8 \text{ lb/hr}$$

Actual annual emissions :

Annual emissions for natural gas and fuel oil are based on CEMs measurement of 33.4 tons/year for both without duct burners and with duct burners. Based on fuel type and quantities burned for both without and with DB, 6.90 tons/year of NO_X was emitted burning natural gas with DB.

Total actual annual emissions = 6.9 tons/year.

Carbon Monoxide

CO emission rate for natural gas is 13.8 lb/hr from Table 3-5.

$$\text{CO Emission Factor} = \frac{13.8 \text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{(1{,}751.1+332)\text{MMBtu}} = \frac{6.62\text{E}-03 \text{ lb}}{\text{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{6.62\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{MMBtu}}{\text{hr}} = 15.1\text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{6.62\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 4.10\text{ tons/year}$$

Volatile Organic Compounds

VOC emission rate for natural gas is 9.21 lb/hr from Table 3-5.

$$\text{VOC Emission Factor} = \frac{9.21\text{ lb}}{\text{hr}} \text{ x } \frac{\text{hr}}{(1{,}751.1+332)\text{MMBtu}} = \frac{4.42\text{E}-03\text{ lb}}{\text{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{4.42\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{MMBtu}}{\text{hr}} = 10.1\text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{4.42\text{E}-03\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 2.74\text{ tons/year}$$

Sulfur Dioxide

Based on 2,000 grains of sulfur/MMscf for natural gas, the AP-42 emission factor of 0.0006 lb/MMBtu is reduced due to 5% conversion to SO_3 in the CTG, 2.5% in the SCR, and 19% in the CO catalyst.

$$SO_2 \text{ Emission Factor} = \frac{0.0006\text{ lb}}{\text{MMBtu}} \text{ x } 0.95 \text{ x } 0.975 \text{ x } 0.81 = 4.50\text{E}-04\text{ lb/MMBtu}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{4.50\text{E}-04\text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{ MMBtu}}{\text{hr}} = 1.03\text{ lb/hr}$$

Actual annual emissions :

$$\text{For natural gas } \frac{4.50\text{E}-04\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 0.279\text{ tons/year}$$

Sulfuric Acid

Based on 2,000 grains of sulfur/MMscf for natural gas, the AP-42 emission factor of 0.0006 lb/MMBtu for SO_2 is adjusted due to 5% conversion to SO_3 in the CTG, 2.5% in the SCR, and 19% in the CO catalyst and then converted to sulfuric acid.

$$H_2SO_4 \text{ Emission Factor} = \frac{0.0006\text{ lb}}{\text{MMBtu}} \text{ x } (1 - 0.95 \text{ x } 0.975 \text{ x } 0.81) \text{ x } \frac{98}{64}$$

$$= 2.29\text{E}-04\text{ lb/MMBtu}$$

Max hourly emissions

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{2.29\text{E}-04\text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{MMBtu}}{\text{hr}} = 0.523\text{ lb/hr}$$

Actual annual emissions

For annual emissions, it is assumed that 99% of the sulfuric acid is converted to ammonium sulfate particulate due to ammonia being fed to the SCR about 99% of the operating time.

$$\text{For natural gas } \frac{2.29\text{E}-04\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} \text{ x } 0.01$$

$$= 0.00142\text{ tons/year}$$

Carbon Dioxide

For natural gas, carbon dioxide equivalent emission factor was determined from 40 CFR Part 98 using the following equation.

$$\left[\frac{53.02\text{ kg }CO_2}{\text{MMBtu}} + \frac{0.001\text{ kg }CH_4}{\text{MMBtu}} \text{ x } \frac{21\text{ kg }CO_2}{\text{kg }CH_4} + \frac{0.0001\text{ kg }N_2O}{\text{MMBtu}} \text{ x } \frac{310\text{ kg }CO_2}{\text{kg }N_2O}\right]$$

$$\text{x } \frac{2.20462\text{ lb}}{1\text{ kg}} = 117\ \frac{\text{lb }CO_2\text{ equiv}}{\text{MMBtu}}$$

Max Hourly emissions:

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{117\text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{MMBtu}}{\text{hr}} = 266{,}534\text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas } \frac{117\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}} = 72{,}391\text{ tons/year}$$

Antimony

Antimony emission factor for natural gas is 1.80E-07 lb/MMBtu from Table 3-17.

Maximum hourly emissions

Maximum heat input at -5°F is 1,930.5 MMBtu/hr for the CTG and 347.5 MMBtu/hr for the duct burner (from Table 3-2).

$$\text{For natural gas } \frac{1.80\text{E}-07\text{ lb}}{\text{MMBtu}} \text{ x } \frac{(1{,}930.5+347.5)\text{MMBtu}}{\text{hr}} = 4.10\text{E}-04\text{ lb/hr}$$

Actual annual emissions

$$\text{For natural gas } \frac{1.80\text{E}-07\text{ lb}}{\text{MMBtu}} \text{ x } \frac{1{,}020\text{ Btu}}{\text{scf}} \text{ x } \frac{1{,}213.15\text{ MMscf}}{\text{yr}} \text{ x } \frac{\text{ton}}{2{,}000\text{ lb}}$$

$$= 1.11\text{E}-04\text{ tons/year}$$

The remaining HAPs are determined as they were for antimony.

TABLE 3-14

Emission Factors for Combustion Turbine Units 1-3 for Simple Cycle Operation, lb/MMBtu [HHV]

Pollutant	Emission Factor, lb/MMBtu [HHV]	
	Natural Gas	Fuel Oil
PM filterable (1)	3.59E-03	8.95E-03
PM 10 filterable (1)	3.59E-03	8.95E-03
PM 2.5 filterable (1)	3.59E-03	8.95E-03
PM condensable (2)	1.34E-04	3.80E-04
Nitrogen Oxides (NOx) (3)	4.35E-02	1.65E-01
Carbon Monoxide (CO) (4)	2.65E-02	4.77E-02
Volatile Organic Compounds (VOC) (5)	1.77E-03	4.10E-03
Sulfur Dioxide (SO_2) (6)	5.70E-04	2.17E-03
Sulfuric Acid (H2SO4) (7)	4.59E-05	1.75E-04
Carbon Dioxide Equivalent (8)	117	164

References

(1) PM for natural gas based on 6.3 lb/hr and heat input at 59°F of 1,755.9 MMBtu/hr.
PM for fuel oil based on 17 lb/hr and heat input at 59°F of 1,900.2 MMBtu/hr.
(2) PM condensable based 5% of VOC emission factor plus sulfuric acid emission factor.
(3) NOx for natural gas based on manufacturer's guarantee of 12 ppm or 76.4 lb/hr emissions and heat input at 59°F of 1,755.9 MMBtu/hr.
NOx for fuel oil based on manufacturer's guarantee of 42 ppm or 313 lb/hr emissions and heat input at 59°F of 1,900.2 MMBtu/hr.
(4) CO for natural gas based on manufacturer's guarantee of 12 ppm or 46.5 lb/hr emissions and heat input at 59°F of 1,755.9 MMBtu/hr.
CO for fuel oil based on manufacturer's guarantee of 20 ppm or 90.7 lb/hr emissions and heat input at 59°F of 1,900.2 MMBtu/hr.
(5) VOC for natural gas based on manufacturer's guarantee of 1.4 ppm or 3.11 lb/hr emissions and heat input at 59°F of 1,755.9 MMBtu/hr.
VOC for fuel oil based on manufacturer's guarantee of 3 ppm or 7.79 lb/hr emissions and heat input at 59°F of 1,900.2 MMBtu/hr.
(6) Based on 95% conversion of sulfur to SO_2, for natural gas (0.0006 lb/MMBtu x 0.95) and for fuel oil with 0.00226 % S (1.01 x 0.00226 x 0.95). AP-42, Section 3.1, 4-00.
(7) Based on 5% conversion of sulfur to SO_3, for natural gas (0.0006 lb/MMBtu x 0.05 x 98/64) and for fuel oil with 0.00226 % S (1.01 x 0.00226 x 0.05 x 98/64). AP-42, Section 3.1, 4-00.
(8) Carbon dioxide equivalent based on 40 CFR Part 98.

TABLE 3-15

Emission Factors for Combustion Turbine Units 1-3 for Combined Cycle Operation without Duct Burners , lb/MMBtu [HHV]

Pollutant	Emission Factor, lb/MMBtu [HHV]	
	Natural Gas	Fuel Oil
PM filterable (1)	3.60E-03	8.96E-03
PM 10 filterable (1)	3.60E-03	8.96E-03
PM 2.5 filterable (1)	3.60E-03	8.96E-03
PM condensable (2)	2.31E-04	7.92E-04
Nitrogen Oxides (NOx) (3)	1.09E-02	7.86E-02
Carbon Monoxide (CO) (4)	6.62E-03	2.38E-02
Volatile Organic Compounds (VOC) (5)	1.90E-03	5.48E-03
Sulfur Dioxide (SO_2) (6)	5.11E-04	1.95E-03
Sulfuric Acid (H2SO4) (7)	1.36E-04	5.17E-04
Carbon Dioxide Equivalent (8)	117	164

References

(1) PM for natural gas based on 6.3 lb/hr and heat input at 60°F of 1,751.1 MMBtu/hr.
PM for fuel oil based on 17 lb/hr and heat input at 60°F of 1,896.3 MMBtu/hr.

(2) PM condensable based 5% of VOC emission factor plus sulfuric acid emission factor.

(3) NOx for natural gas based on manufacturer's guarantee of 3 ppm or 19 lb/hr emissions and heat input at 60°F of 1,751.1 MMBtu/hr.
NOx for fuel oil based on manufacturer's guarantee of 20 ppm or 149 lb/hr emissions and heat input at 60°F of 1,896.3 MMBtu/hr.

(4) CO for natural gas based on manufacturer's guarantee of 3 ppm or 11.6 lb/hr emissions and heat input at 60°F of 1,751.1 MMBtu/hr.
CO for fuel oil based on manufacturer's guarantee of 10 ppm or 45.2 lb/hr emissions and heat input at 60°F of 1,896.3 MMBtu/hr.

(5) VOC for natural gas based on manufacturer's guarantee of 1.5 ppm or 3.32 lb/hr emissions and heat input at 60°F of 1,751.1 MMBtu/hr.
VOC for fuel oil based on manufacturer's guarantee of 4 ppm or 10.4 lb/hr emissions and heat input at 60°F of 1,896.3 MMBtu/hr.

(6) Based on 5% conversion of sulfur to SO_3 in the CT, 2.5% in the SCR, and 8% in the CO catalyst. For natural gas (0.0006 lb/MMBtu x 0.95 x 0.975 x 0.92) and for fuel oil with 0.00226 % S (1.01 x 0.00226 x 0.95 x 0.975 x 0.92). AP-42, Section 3.1, 4-00.

(7) Based on 5% conversion of sulfur to SO_3 in the CT, 2.5% in the SCR, and 8% in the CO catalyst. For natural gas (0.0006 lb/MMBtu x (1-0.95 x 0.975 x 0.92) x 98/64) and for fuel oil with 0.00226 % S (1.01 x 0.00226 x (1-0.95 x 0.975 x 0.92) x 98/64). AP-42, Section 3.1, 4-00.

(8) Carbon dioxide equivalent based on 40 CFR Part 98.

TABLE 3-16

Emission Factors for Combustion Turbine Units 1-3 for Combined Cycle Operation with Duct Burners , lb/MMBtu [HHV]

Pollutant	Emission Factor, lb/MMBtu [HHV]
	Natural Gas
PM filterable [1]	4.14E-03
PM 10 filterable [1]	4.14E-03
PM 2.5 filterable [1]	4.14E-03
PM condensable [2]	4.50E-04
Nitrogen Oxides (NOx) [3]	1.09E-02
Carbon Monoxide (CO) [4]	6.62E-03
Volatile Organic Compounds (VOC) [5]	4.42E-03
Sulfur Dioxide (SO_2) [6]	4.50E-04
Sulfuric Acid (H2SO4) [7]	2.29E-04
Carbon Dioxide Equivalent [8]	117

References

(1) PM for natural gas based on 6.3 lb/hr and heat input at 60°F of 1,751.1 MMBtu/hr for the CT and duct burner PM emission factor of 0.01 lb/MMBtu, 30% reduction factor based on tests, and heat input at 60°F of 332 MMBtu/hr for the duct burner.
(2) PM condensable based 5% of VOC emission factor plus sulfuric acid emission factor.
(3) NOx for natural gas based on manufacturer's guarantee of 3 ppm or 22.6 lb/hr emissions and heat input at 60°F of 1,751.1 MMBtu/hr for the CT and 332 MMBtu/hr for the duct burner.
(4) CO for natural gas based on manufacturer's guarantee of 3 ppm or 13.8 lb/hr emissions and heat input at 60°F of 1,751.1 MMBtu/hr for the CT and 332 MMBtu/hr for the duct burner.
(5) VOC for natural gas based on manufacturer's guarantee of 3.5 ppm or 9.21 lb/hr emissions and heat input at 60°F of 1,751.1 MMBtu/hr for the CT and 332 MMBtu/hr for the duct burner.
(6) Based on 5% conversion of sulfur to SO_3 in the CT, 2.5% in the SCR, and 19% in the CO catalyst. For natural gas (0.0006 lb/MMBtu x 0.95 x 0.975 x 0.81). AP-42, Section 3.1, 4-00.
(7) Based on 5% conversion of sulfur to SO_3 in the CT, 2.5% in the SCR, and 19% in the CO catalyst. For natural gas (0.0006 lb/MMBtu x (1-0.95 x 0.975 x 0.81) x 98/64). AP-42, Section 3.1, 4-00.
(8) Carbon dioxide equivalent based on 40 CFR Part 98.

TABLE 3-17

Trace Species Emission Factors for Combustion Turbine Units 1-3, lb/10^12 Btu [HHV]

Pollutant		Emission Factor, lb/10^12 Btu [HHV]			References	
		Natural Gas	Fuel Oil		Natural Gas	Fuel Oil
Antimony (Sb)		0.18	22		1	2
Arsenic (As)		0.23	11		3	4
Beryllium (Be)		0.01	0.31		3	4
Cadmium (Cd)		0.04	4.8		3	4
Chromium (Cr)		1.1	11		3	4
Cobalt (Co)		0.08	9.1		3	2
Lead (Pb)		0.4	14		3	4
Manganese (Mn)		0.4	101		3	5
Mercury (Hg)		0.0008	1.2		3	4
Nickel (Ni)		2.4	4.6		3	4
Selenium (Se)		0.02	25		3	4
Hydrogen Chloride (HCl)			311			5
1,3-Butadiene (106990)		0.43	16		4	4
Acetaldehyde (75070)		40			4	
Acrolein (107028)		6.4			4	
Benzene (71432)		12	55		4	4
Ethyl benzene (100414)		32			4	
Formaldehyde (50000)		135	230		6	7
Naphthalene (91203)		1.3	35		4	4
Propylene Oxide (75569)		29			4	
Toluene (108883)		130			4	
Xylenes (1330207)		64			4	
POM Total		2.2	40		4	4

References

(1) US EPA, Air Emissions from Scrap Tire Combustion, EPA-600/R-97-115, October 1997 (Emission data for a NG-fired rotary-kiln incinerator simulator).
(2) US EPA, Compilation of Air Pollutant Emission Factors (AP-42), Vol. I, 5th Edition, Supplement B, Section 3.1, Stationary Gas Turbines, Table 3.1-4, 10-96.
(3) Emission Factors Handbook [EFH]--Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, Electric Power Research Institute (EPRI), Report No. EPRI TR-105611, 11-95, Table 4-1 ("Uncontrolled Gas-Fired Boiler Emission Factors").
(4) US EPA, Compilation of Air Pollutant Emission Factors (AP-42), Vol. I, 5th Edition, Supplement F, Section 3.1, Stationary Gas Turbines, 4-00.
(5) TVA Combustion Turbine Fuel Oil Specifications (#2 Distillate) Revision 5.0, 1-17-01.
(6) Access database (file "r03s01.zip") downloaded from EPA's CHIEF Website 4-16-01.
(7) Adjusted AP-42 emission factor.

Note on Ref. 3: While EPRI cautioned against using the data in Table 4-1 for gas-fired turbines, TVA believes that the trace-element emission factors should be reasonably applicable to CT units. Fuel composition determines trace-element emissions (mass-per-unit-energy basis) whether burned in a boiler or a CT unit.

Note that analyses for several species were reported as non-detects, but emission factors were based on minimum detection limits (MDL). AP-42 (Supplmt. F) emission factors for As, Be, Ni, Se (fuel oil), 1,3-butadiene (fuel oil & natural gas), & propylene oxide (natural gas) are based on 0.5 x MDL.

TABLE 3-18

Actual AY 2012 Emissions for Simple Cycle Operation at John Sevier Combustion Turbine Plant

		Reference
Actual natural gas usage, MMscf/yr	320.44	AY 2012 Data Collection
Actual fuel oil usage, gal/yr	0	AY 2012 Data Collection
Natural gas nominal heat content, Btu/scf	1,020	AP-42, Volume 1, 5th Edition, Supplement F, Table 3.1-1, April 2000
Natural gas sulfur to SO_3 conversion, %	5.00	Engineering Estimate
Fuel oil heat content, Btu/gal	137,817	AY 2012 Data Collection
Fuel oil sulfur content, %	0.00226	AY 2012 Data Collection
Maximum fuel oil sulfur content, %	0.05	Maximum Sulfur Content
Fuel oil sulfur to SO_3 conversion, %	5.00	Engineering Estimate
Margin for PM emission estimates, %	5.00	Vendor info

Pollutant	Emission Factor, lb/MMBtu [HHV]		Max Hourly Emissions lb/CT-hr		Annual Emissions ton/yr		
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil	Total
PM filterable	3.59E-03	8.95E-03	6.62	17.9	0.586	0.00	0.586
PM 10 filterable	3.59E-03	8.95E-03	6.62	17.9	0.586	0.00	0.586
PM 2.5 filterable	3.59E-03	8.95E-03	6.62	17.9	0.586	0.00	0.586
PM condensable	1.34E-04	3.80E-04	0.273	8.45	0.0220	0.00	0.0220
Nitrogen Oxides (NOx)	4.35E-02	1.65E-01	84.1	326	6.05	0.00	6.05
Carbon Monoxide (CO)	2.65E-02	4.77E-02	51.2	94.4	4.33	0.00	4.33
Volatile Organic Compounds (VOC)	1.77E-03	4.10E-03	3.42	8.11	0.289	0.00	0.289
Sulfur Dioxide (SO_2)	5.70E-04	2.17E-03	1.10	94.9	0.0932	0.00	0.0932
Sulfuric Acid (H_2SO_4)	4.59E-05	1.75E-04	0.0887	7.65	0.00751	0.00	0.00751
Carbon Dioxide Equivalent	117	164	226,039	323,590	19,121	0.00	19,121
Antimony (Sb)	1.80E-07	2.20E-05	3.48E-04	4.35E-02	2.94E-05	0.00	2.94E-05
Arsenic (As)	2.30E-07	1.10E-05	4.44E-04	2.18E-02	3.76E-05	0.00	3.76E-05
Beryllium (Be)	1.00E-08	3.10E-07	1.93E-05	6.13E-04	1.63E-06	0.00	1.63E-06
Cadmium (Cd)	4.00E-08	4.80E-06	7.73E-05	9.49E-03	6.54E-06	0.00	6.54E-06
Chromium (Cr)	1.10E-06	1.10E-05	2.13E-03	2.18E-02	1.80E-04	0.00	1.80E-04
Cobalt (Co)	8.00E-08	9.10E-06	1.55E-04	1.80E-02	1.31E-05	0.00	1.31E-05
Lead (Pb)	4.00E-07	1.40E-05	7.73E-04	2.77E-02	6.54E-05	0.00	6.54E-05
Manganese (Mn)	4.00E-07	1.01E-04	7.73E-04	1.99E-01	6.54E-05	0.00	6.54E-05
Mercury (Hg)	8.00E-10	1.20E-06	1.55E-06	2.37E-03	1.31E-07	0.00	1.31E-07
Nickel (Ni)	2.40E-06	4.60E-06	4.64E-03	9.10E-03	3.92E-04	0.00	3.92E-04
Selenium (Se)	2.00E-08	2.50E-05	3.86E-05	4.94E-02	3.27E-06	0.00	3.27E-06
Hydrogen Chloride (HCl)		3.11E-04		6.15E-01		0.00	0.00E+00
Particulate HAP Total*	4.84E-06	1.78E-04	9.35E-03	3.51E-01	7.91E-04	0.00	7.91E-04
1,3-Butadiene	4.30E-07	1.60E-05	8.31E-04	3.16E-02	7.03E-05	0.00	7.03E-05
Acetaldehyde	4.00E-05		7.73E-02		6.54E-03		6.54E-03
Acrolein	6.40E-06		1.24E-02		1.05E-03		1.05E-03
Benzene	1.20E-05	5.50E-05	2.32E-02	1.09E-01	1.96E-03	0.00	1.96E-03
Ethyl benzene	3.20E-05		6.18E-02		5.23E-03		5.23E-03
Formaldehyde	1.35E-04	2.30E-04	2.61E-01	4.55E-01	2.21E-02	0.00	2.21E-02
Naphthalene	1.30E-06	3.50E-05	2.51E-03	6.92E-02	2.12E-04	0.00	2.12E-04
Propylene Oxide	2.90E-05		5.60E-02		4.74E-03		4.74E-03
Toluene	1.30E-04		2.51E-01		2.12E-02		2.12E-02
Xylenes	6.40E-05		1.24E-01		1.05E-02		1.05E-02
POM Total	2.20E-06	4.00E-05	4.25E-03	7.91E-02	3.60E-04	0.00	3.60E-04
VOC HAP Total**	4.52E-04	3.76E-04	8.74E-01	7.44E-01	7.39E-02	0.00	7.39E-02
Non-VOC Gaseous HAP Total***	2.08E-08	3.37E-04	4.02E-05	6.66E-01	3.40E-06	0.00	3.40E-06

Annual emissions for NOx based on CEMs.

* Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel.
** Includes 1,3-butadiene, acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, propylene oxide, toluene, xylenes, and total POMs.
*** Includes mercury, selenium, and hydrogen chloride.

TABLE 3-19

Actual AY 2012 Emissions for Combined Cycle Operation (without DB) at John Sevier Combustion Turbine Plant

		Reference
Actual natural gas usage, MMscf/yr	4,657.83	AY 2012 Data Collection
Actual fuel oil usage, gal/yr	81.7	AY 2012 Data Collection
Natural gas nominal heat content, Btu/scf	1,020	AP-42, Volume 1, 5th Edition, Supplement F, Table 3.1-1, April 2000
Natural gas sulfur to SO_3 conversion, %	5.00	Engineering Estimate
Fuel oil heat content, Btu/gal	137,817	AY 2012 Data Collection
Fuel oil sulfur content, %	0.00226	AY 2012 Data Collection
Maximum fuel oil sulfur content, %	0.05	Maximum Sulfur Content
Fuel oil sulfur to SO_3 conversion, %	5.00	Engineering Estimate
Margin for PM emission estimates, %	5.00	Vendor info

Pollutant	Emission Factor, lb/MMBtu [HHV]		Max Hourly Emissions lb/CT-hr		Annual Emissions ton/yr		
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil	Total
PM filterable	3.60E-03	8.96E-03	6.97	48.5	8.98	5.44E-05	8.98
PM 10 filterable	3.60E-03	8.96E-03	6.97	48.5	8.98	5.44E-05	8.98
PM 2.5 filterable	3.60E-03	8.96E-03	6.97	48.5	8.98	5.44E-05	8.98
PM condensable	2.31E-04	7.92E-04	0.467	24.4	0.228	1.57E-06	0.228
Nitrogen Oxides (NOx)	1.09E-02	7.86E-02	21.0	156	26.5	4.55E-04	26.5
Carbon Monoxide (CO)	6.62E-03	2.38E-02	12.8	47.4	15.7	1.34E-04	15.7
Volatile Organic Compounds (VOC)	1.90E-03	5.48E-03	3.66	10.9	4.50	3.09E-05	4.50
Sulfur Dioxide (SO_2)	5.11E-04	1.95E-03	0.987	85.5	1.21	1.10E-05	1.21
Sulfuric Acid (H_2SO_4)	1.36E-04	5.17E-04	0.262	22.7	0.00323	2.91E-08	0.00323
Carbon Dioxide Equivalent	117	164	225,875	325,209	277,941	0.921	277,942
Antimony (Sb)	1.80E-07	2.20E-05	3.47E-04	4.37E-02	4.28E-04	1.24E-07	4.28E-04
Arsenic (As)	2.30E-07	1.10E-05	4.44E-04	2.19E-02	5.46E-04	6.19E-08	5.46E-04
Beryllium (Be)	1.00E-08	3.10E-07	1.93E-05	6.16E-04	2.38E-05	1.75E-09	2.38E-05
Cadmium (Cd)	4.00E-08	4.80E-06	7.72E-05	9.54E-03	9.50E-05	2.70E-08	9.50E-05
Chromium (Cr)	1.10E-06	1.10E-05	2.12E-03	2.19E-02	2.61E-03	6.19E-08	2.61E-03
Cobalt (Co)	8.00E-08	9.10E-06	1.54E-04	1.81E-02	1.90E-04	5.12E-08	1.90E-04
Lead (Pb)	4.00E-07	1.40E-05	7.72E-04	2.78E-02	9.50E-04	7.88E-08	9.50E-04
Manganese (Mn)	4.00E-07	1.01E-04	7.72E-04	2.00E-01	9.50E-04	5.67E-07	9.51E-04
Mercury (Hg)	8.00E-10	1.20E-06	1.54E-06	2.39E-03	1.90E-06	6.76E-09	1.91E-06
Nickel (Ni)	2.40E-06	4.60E-06	4.63E-03	9.14E-03	5.70E-03	2.59E-08	5.70E-03
Selenium (Se)	2.00E-08	2.50E-05	3.86E-05	4.97E-02	4.75E-05	1.41E-07	4.77E-05
Hydrogen Chloride (HCl)		3.11E-04		6.18E-01		1.75E-06	1.75E-06
Particulate HAP Total*	4.84E-06	1.78E-04	9.34E-03	3.53E-01	1.15E-02	9.99E-07	1.15E-02
1,3-Butadiene	4.30E-07	1.60E-05	8.30E-04	3.18E-02	1.02E-03	9.01E-08	1.02E-03
Acetaldehyde	4.00E-05		7.72E-02		9.50E-02		9.50E-02
Acrolein	6.40E-06		1.24E-02		1.52E-02		1.52E-02
Benzene	1.20E-05	5.50E-05	2.32E-02	1.09E-01	2.85E-02	3.10E-07	2.85E-02
Ethyl benzene	3.20E-05		6.18E-02		7.60E-02		7.60E-02
Formaldehyde	1.35E-04	2.30E-04	2.61E-01	4.57E-01	3.21E-01	1.29E-06	3.21E-01
Naphthalene	1.30E-06	3.50E-05	2.51E-03	6.96E-02	3.09E-03	1.97E-07	3.09E-03
Propylene Oxide	2.90E-05		5.60E-02		6.89E-02		6.89E-02
Toluene	1.30E-04		2.51E-01		3.09E-01		3.09E-01
Xylenes	6.40E-05		1.24E-01		1.52E-01		1.52E-01
POM Total	2.20E-06	4.00E-05	4.25E-03	7.95E-02	5.23E-03	2.25E-07	5.23E-03
VOC HAP Total**	4.52E-04	3.76E-04	8.73E-01	7.47E-01	1.07E+00	2.12E-06	1.07E+00
Non-VOC Gaseous HAP Total***	2.08E-08	3.37E-04	4.02E-05	6.70E-01	4.94E-05	1.90E-06	5.13E-05

Annual emissions for NOx based on CEMs.

* Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel.
** Includes 1,3-butadiene, acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, propylene oxide, toluene, xylenes, and total POMs.
*** Includes mercury, selenium, and hydrogen chloride.

TABLE 3-20

Actual AY 2012 Emissions for Combined Cycle Operation (with DB) at John Sevier Combustion Turbine Plant

		Reference
Actual natural gas usage, MMscf/yr	1,213.15	AY 2012 Data Collection
Natural gas nominal heat content, Btu/scf	1,020	AP-42, Vol. 1, 5th Ed., Supplement F, Table 3.1-1, April 2000
Natural gas sulfur to SO_3 conversion, %	5.00	Engineering Estimate
Duct burner PM emission factor, lb/MMBtu	0.01	Vendor info
PM emission factor adjustment for natural gas, %	30	Vendor info
Margin for PM emission estimates, %	5.00	Vendor info

Pollutant	Emission Factor, lb/MMBtu [HHV]	Max Hourly Emissions lb/CT-hr	Annual Emissions ton/yr
	Natural Gas	Natural Gas	Natural Gas
PM filterable	4.14E-03	9.87	2.75
PM 10 filterable	4.14E-03	9.87	2.75
PM 2.5 filterable	4.14E-03	9.87	2.75
PM condensable	4.50E-04	1.08	0.138
Nitrogen Oxides (NOx)	1.09E-02	24.8	6.90
Carbon Monoxide (CO)	6.62E-03	15.1	4.10
Volatile Organic Compounds (VOC)	4.42E-03	10.1	2.74
Sulfur Dioxide (SO_2)	4.50E-04	1.03	0.279
Sulfuric Acid (H_2SO_4)	2.29E-04	0.523	0.00142
Carbon Dioxide Equivalent	117	266,534	72,391
Antimony (Sb)	1.80E-07	4.10E-04	1.11E-04
Arsenic (As)	2.30E-07	5.24E-04	1.42E-04
Beryllium (Be)	1.00E-08	2.28E-05	6.19E-06
Cadmium (Cd)	4.00E-08	9.11E-05	2.47E-05
Chromium (Cr)	1.10E-06	2.51E-03	6.81E-04
Cobalt (Co)	8.00E-08	1.82E-04	4.95E-05
Lead (Pb)	4.00E-07	9.11E-04	2.47E-04
Manganese (Mn)	4.00E-07	9.11E-04	2.47E-04
Mercury (Hg)	8.00E-10	1.82E-06	4.95E-07
Nickel (Ni)	2.40E-06	5.47E-03	1.48E-03
Selenium (Se)	2.00E-08	4.56E-05	1.24E-05
Hydrogen Chloride (HCl)			
Particulate HAP Total*	4.84E-06	1.10E-02	2.99E-03
1,3-Butadiene	4.30E-07	9.80E-04	2.66E-04
Acetaldehyde	4.00E-05	9.11E-02	2.47E-02
Acrolein	6.40E-06	1.46E-02	3.96E-03
Benzene	1.20E-05	2.73E-02	7.42E-03
Ethyl benzene	3.20E-05	7.29E-02	1.98E-02
Formaldehyde	1.35E-04	3.08E-01	8.35E-02
Naphthalene	1.30E-06	2.96E-03	8.04E-04
Propylene Oxide	2.90E-05	6.61E-02	1.79E-02
Toluene	1.30E-04	2.96E-01	8.04E-02
Xylenes	6.40E-05	1.46E-01	3.96E-02
POM Total	2.20E-06	5.01E-03	1.36E-03
VOC HAP Total**	4.52E-04	1.03E+00	2.80E-01
Non-VOC Gaseous HAP Total***	2.08E-08	4.74E-05	1.29E-05

Annual emissions for NOx based on CEMs.

* Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel.
** Includes 1,3-butadiene, acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, propylene oxide, toluene, xylenes, and total POMs.
*** Includes mercury, selenium, and hydrogen chloride.

TABLE 3-21

JSF Combustion-Turbine (CT) Startup (SU)/Shutdown (SD) Cycling-Mode Emission Estimates

AY12 JCC Startups by Unit and Type [1]

Type	NG-Fired				Oil-Fired			
Unit #	CT1	CT2	CT3	JCC Total	CT1	CT2	CT3	JCC Total
Hot SU (HSU)	10	7	6	23	0	0	0	0
Warm SU (WSU)	0	0	1	1	0	0	0	0
Cold SU (CSU)	1	1	1	3	0	0	0	0
SD	11	8	8	27	0	0	0	0

[1] Per Excel file "AY12 Combined Cycle CT Questionnaire.xlsx" in 9-20-12 e-mail from B.R. Marlin to J.D. Lokey (# of startups), and 9-27-12 e-mail from J.D. Lokey to L.C. Smallwood et al. (fuel assumption).

TABLE 3-22

Startup/Shutdown Emission Estimates, lb/SU-SD

Type of Operation	CT Unit Status	CT Unit No.	Fuel	NOx	CO	VOC	SO_2	PM-fil	PM-cond	H_2SO_4
Hot SU	Lead	1	NG	109.3	906.6	152.5	0.2262	7.054	7.683	0.06008
			Oil	242.4	811.5	119.5	1.309	18.38	6.322	0.3478
	Lag	2	NG	67.12	805.8	134.1	0.1277	4.366	6.738	0.03392
			Oil	109.3	775.5	117.2	0.5025	6.820	5.994	0.1335
Warm SU	Lead	1	NG	222.1	1148.7	222.2	0.4992	18.26	11.24	0.1326
			Oil	400.8	1628.7	141.0	2.864	49.79	7.809	0.7607
	Lag	2	NG	110.1	909.8	153.2	0.2282	7.107	7.722	0.06062
			Oil	207.3	783.1	118.2	0.9548	12.27	6.162	0.2536
Cold SU	Lead	1	NG	415.9	1759.8	277.3	0.9975	38.46	14.13	0.2650
			Oil	575.5	2998.8	172.4	4.336	79.59	9.770	1.152
	Lag	2	NG	168.2	1048.5	178.6	0.3638	10.82	9.028	0.09665
			Oil	338.1	793.3	119.4	1.558	19.53	6.386	0.4138
SD		3	NG	15.51	22.00	5.616	0.1349	2.370	0.3166	0.03584
			Oil	39.88	12.79	1.041	0.5515	4.477	0.1985	0.1465

	NOx ton/yr	CO ton/yr	VOC ton/yr	SO_2 ton/yr	PM-fil ton/yr	PM-cond ton/yr	H_2SO_4 ton/yr
Hot SU	0.983	9.77	1.63	0.00196	0.0636	0.0822	0.000521
Warm SU	0.0551	0.455	0.0766	0.000114	0.00355	0.00386	0.0000303
Cold SU	0.376	1.93	0.317	0.000863	0.0301	0.0161	0.000229
SD	0.209	0.297	0.0758	0.00182	0.0320	0.00427	0.000484
Total	1.62	12.5	2.10	0.00476	0.129	0.106	0.00126

Sample Calculation

for NOx — CT1 NG, CT2 NG, CT3 NG, CT1 Oil, CT2 Oil, CT3 oil

Hot SU = (10 x 109.3 + 7 x 67.12 + 6 x 67.12 + 0 x 242.4 + 0 x 109.3 + 0 x 109.3)/2000 = 0.983 ton/yr

Warm SU = (0 x 222.1 + 0 x 110.1 + 1 x 110.1 + 0 x 400.8 + 0 x 207.3 + 0 x 207.3)/2000 = 0.0551 ton/yr

Cold SU = (1 x 415.9 + 1 x 168.2 + 1 x 168.2 + 0 x 575.5 + 0 x 338.1 + 0 x 338.1)/2000 = 0.376 ton/yr

SD = (27 x 15.51 + 0 x 39.88)/2000 = 0.209 ton/yr

Total = 0.983 + 0.0551 + 0.376 + 0.209 = 1.62 ton/yr

TABLE 3-23

Actual AY 2012 Emissions Summary from John Sevier Combustion Turbines

Pollutant	Simple Cycle CT ton/yr	Combined Cycle CT ton/yr	CT Startup/Shutdown ton/yr	Total ton/yr
PM filterable	0.586	11.7	0.129	12.4
PM 10 filterable	0.586	11.7	0.129	12.4
PM 2.5 filterable	0.586	11.7	0.129	12.4
PM condensable	0.0220	0.367	0.106	0.495
Nitrogen Oxides (NOx)	6.05	33.4	1.62	39.5
Carbon Monoxide (CO)	4.33	19.8	12.5	36.6
Volatile Organic Compounds (VOC)	0.289	7.24	2.10	9.63
Sulfur Dioxide (SO_2)	0.0932	1.49	0.00476	1.59
Sulfuric Acid (H_2SO_4)	0.00751	0.00465	0.00126	0.0134
Carbon Dioxide Equivalent	19,121	350,333		369,454
Antimony (Sb)	2.94E-05	5.39E-04		5.68E-04
Arsenic (As)	3.76E-05	6.89E-04		7.26E-04
Beryllium (Be)	1.63E-06	2.99E-05		3.16E-05
Cadmium (Cd)	6.54E-06	1.20E-04		1.26E-04
Chromium (Cr)	1.80E-04	3.29E-03		3.47E-03
Cobalt (Co)	1.31E-05	2.40E-04		2.53E-04
Lead (Pb)	6.54E-05	1.20E-03		1.26E-03
Manganese (Mn)	6.54E-05	1.20E-03		1.26E-03
Mercury (Hg)	1.31E-07	2.40E-06		2.53E-06
Nickel (Ni)	3.92E-04	7.19E-03		7.58E-03
Selenium (Se)	3.27E-06	6.00E-05		6.33E-05
Hydrogen Chloride (HCl)	0.00E+00	1.75E-06		1.75E-06
Particulate HAP Total*	7.91E-04	1.45E-02		1.53E-02
1,3-Butadiene	7.03E-05	1.29E-03		1.36E-03
Acetaldehyde	6.54E-03	1.20E-01		1.26E-01
Acrolein	1.05E-03	1.92E-02		2.02E-02
Benzene	1.96E-03	3.59E-02		3.79E-02
Dichlorobenzene				0.00E+00
Ethyl benzene	5.23E-03	9.58E-02		1.01E-01
Formaldehyde	2.21E-02	4.04E-01		4.26E-01
n-Hexane				0.00E+00
Naphthalene	2.12E-04	3.89E-03		4.11E-03
Propylene Oxide	4.74E-03	8.68E-02		9.16E-02
Toluene	2.12E-02	3.89E-01		4.10E-01
Xylenes	1.05E-02	1.92E-01		2.02E-01
POM Total	3.60E-04	6.59E-03		6.95E-03
VOC HAP Total**	7.39E-02	1.35		1.43
Non-VOC Gaseous HAP Total***	3.40E-06	6.42E-05		6.76E-05

* Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel.
** Includes 1,3-butadiene, acetaldehyde, acrolein, benzene, dichlorobenzene, ethyl benzene, formaldehyde, n-hexane, naphthalene, propylene oxide, toluene, xylenes, and total POMs.
*** Includes mercury, selenium, and hydrogen chloride.

ATTACHMENT 3

CUSTOM MONITORING SCHEDULE
40 CFR 60 SUBPART KKKK

CUSTOM MONITORING SCHEDULE
40 CFR 60 SUBPART KKKK

John Sevier Combined Cycle Plant (JSCC) is requesting a custom monitoring schedule for their three stationary gas turbines which are subject to the Federal New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK. The facility will use dry low NO_X burners while firing natural gas and water injection while firing fuel oil to reduce NO_X emissions. For combined cycle operation, SCRs will be used to further reduce NO_X emissions. CEMs will be used to monitor the NO_X emissions during simple cycle and combined cycle operation and to verify proper operation of the SCRs during combined cycle operation.

40 CFR §60.4370(c) allows owners to request custom fuel monitoring schedules. JSCC is requesting approval for testing of the natural gas that is consistent with similar custom fuel monitoring schedules approved for other facilities. The facility will sample the natural gas for sulfur content every six months, except when firing pipeline quality natural gas as the sulfur content is assumed to be in compliance and testing is not required. The sampling will be conducted using methods approved by the TDEC-APC and U.S. EPA.

With respect to testing of the fuel oil, JSCC will use vendor analyses for fuel oil sulfur content which is tested in accordance with requirements of 40 CFR 75 Appendix D. These sulfur testing requirements are at least as stringent as the Subpart KKKK oil sulfur testing requirements.

ATTACHMENT 4

TRANSPORT RULE REQUIREMENTS

Transport Rule (TR) Trading Program Title V Requirements

Description of TR Monitoring Provisions

The TR subject unit(s), and the unit-specific monitoring provisions at this source, are identified in the following table(s). These unit(s) are subject to the requirements for the TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program.

Unit ID:					
Parameter	**CEMS requirements pursuant to 40 CFR part 75, Subparts B (SO_2 monitoring) and H (NO_X monitoring)**	**Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR 75, Appendix D**	**Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR 75, Appendix E**	**Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to §75.19**	**EPA-approved alternative monitoring system requirements pursuant to 40 CFR 75 Subpart E**
SO_2	X		----------------		
NO_X	X	-------------			
Heat Input	X		----------------		

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR §§97.430 through 97.435" *TR NO_X Annual Trading Program),* §§97.530 through 97.535 *(TR NO_X Ozone Season Trading Program),* and §§97.630 through 97.635 *(TR SO_2 Group 1 Trading Program)*. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with §§75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR 75 Subpart E and §75.66 and §97.435, §97.535, and §97.635, as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR §§97.430 through 97.434, §§97.530 through 97.534, or §§97.630 through 97.634 must submit to the Administrator a petition requesting approval of the alternative in accordance with §75.66 and §97.435, §97.535, and §97.635, as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirements of §§97.430 through 97.434, §§97.530 through 97.534, and §§97.630 through 97.634, as applicable, and minor permit modification procedures, in accordance with §70.7(e)(2)(i)(B) or §71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

TR NO_X Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) TR NO_X Annual emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii) If total NO_X emissions during a control period in a given year from the TR NO_X Annual units at a TR NO_X Annual source are in excess of the TR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A) The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B) The owners and operators of the source and each TR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) TR NO_X Annual assurance provisions.

(i) If total NO_X emissions during a control period in a given year from all TR NO_X Annual units at TR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the state for such control period exceed the state assurance level.

(ii) The owners and operators shall hold the TR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv) It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Annual units at TR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i) A TR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii) A TR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR NO_X Annual Trading Program; and

(ii) Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each TR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

TR NO_X Ozone Season Trading Program Requirements (40 CFR 97.506)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.513 through 97.518.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.530 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.531 (initial monitoring system certification and recertification procedures), 97.532 (monitoring system out-of-control periods), 97.533 (notifications concerning monitoring), 97.534 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.535 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) TR NO_X Ozone Season emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(ii) If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source are in excess of the TR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under 40 CFR 97.524(d); and

(B) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions.

(i) If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state for such control period exceed the state assurance level.

(ii) The owners and operators shall hold the TR NO_X Ozone Season allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).

(iv) It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR NO_X Ozone Season allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(3) Compliance periods.

(i) A TR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(ii) A TR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR NO_X Ozone Season allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR NO_X Ozone Season allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR NO_X Ozone Season allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_X Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart BBBBB.

(6) Limited authorization. A TR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR NO_X Ozone Season Trading Program; and

(ii) Notwithstanding any other provision of 40 CFR part 97, subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Ozone Season allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBBB.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.530 through 97.535, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.506(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.516 for the designated representative for the source and each TR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.516 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart BBBBB.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Trading Program.

(2) The designated representative of a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall make all submissions required under the TR NO_X Ozone Season Trading Program, except as provided in 40 CFR 97.518. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(2) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR NO_X Ozone Season Trading Program or exemption under 40 CFR 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season source or TR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

TR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) TR SO_2 Group 1 emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii) If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source are in excess of the TR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) TR SO_2 Group 1 assurance provisions.

(i) If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(ii) The owners and operators shall hold the TR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv) It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i) A TR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii) A TR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO_2 Group 1 Trading Program; and

(ii) Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR part 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E), Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with 40 CFR part 97, subpart CCCCC.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(2) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) **Effect on other authorities.** No provision of the TR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

ATTACHMENT 5

ACID RAIN PERMIT

TENNESSEE AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243-1531

PHASE II ACID RAIN PERMIT

This permit fulfills the requirements of the federal regulations promulgated at 40 CFR Parts 72, 73, 75, 76, 77, and 78. This permit is issued in accordance with the applicable provisions of rule 1200-3-30 of the Tennessee Air Pollution Control Regulations. The permittee has been granted permission to operate an air contaminant source in accordance with emissions limitations and monitoring requirements set forth herein.

Date Issued: April 29, 2014
Effective Dates: April 29, 2014, through April 28, 2019
Permit Number: 867995

Issued By:
Tennessee Air Pollution Control Board
Tennessee Department of Environment and Conservation

Issued To:
Tennessee Valley Authority
John Sevier Combined Cycle and Fossil Plant

Installation Address:
Highway 70 South
Rogersville

Emission Source Reference Number: 37-0007
ORIS/Facility Code: 3405

ACID RAIN PERMIT CONTENTS:

1. Statement of Basis.

2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3. Standard Requirements (40 CFR 72.9 and TAPCR 1200-3-30-.01(6))

4. Comments, notes, and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4. The permit application and NO_X compliance plan submitted for this source, as corrected by the Tennessee Department of Environment and Conservation. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

5. Summary of previous actions and present action.

TECHNICAL SECRETARY

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

POST AT INSTALLATION ADDRESS

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Tennessee Code Annotated 68-201-105 and 4-5-202 and Titles IV and V of the Clean Air Act, the Tennessee Air Pollution Control Board and Tennessee Department of Environment and Conservation issue this permit pursuant to Chapter 1200-3-30 and Paragraph 1200-3-9-.02(11) of the Tennessee Air Pollution Control Regulations and 40 CFR Part 76 of the Federal Regulations.

2. SO_2 Allowance Allocations and NO_x Requirements for each affected unit

<table>
<tr><th></th><th></th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th></tr>
<tr><td rowspan="2">Unit 1</td><td>SO₂ allowances, under Tables 2, 3, or 4 of 40 CFR part 73.</td><td>6,372</td><td>6,372</td><td>6,372</td><td>6,372</td><td>6,372</td></tr>
<tr><td>NO_X limit</td><td colspan="5">Pursuant to 40 CFR Part 76, the Tennessee Department of Environment and Conservation approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2010, 2011, 2012, 2013, and 2014. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of 0.42 lb/MMBtu. In addition, this unit shall not have an annual heat input greater than 12,648,030 MMBtu.

Under each plan, the actual Btu-weighted annual average NO_X emissions rate for the units in each plan shall be less than or equal to the Btu-weighted annual average NO_X emissions rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emissions limitations under 40 CFR Part 76.5, 76.6, or 76.7, except that for any early election units, the applicable emissions limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under each respective plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plans shall be final only when the Alabama Department of Environmental Management, Kentucky Department for Environmental Protection, and Memphis-Shelby County Health Department have also approved the averaging plans.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.</td></tr>
</table>

<table>
<tr><th></th><th></th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th></tr>
<tr><td rowspan="2">Unit 2</td><td>SO₂ allowances, under Tables 2, 3, or 4 of 40 CFR part 73.</td><td>6,369</td><td>6,369</td><td>6,369</td><td>6,369</td><td>6,369</td></tr>
<tr><td>NO_X limit</td><td colspan="5">Pursuant to 40 CFR Part 76, the Tennessee Department of Environment and Conservation approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2010, 2011, 2012, 2013, and 2014. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of 0.42 lb/MMBtu. In addition, this unit shall not have an annual heat input greater than 12,651,121 MMBtu.

Under each plan, the actual Btu-weighted annual average NO_X emissions rate for the units in each plan shall be less than or equal to the Btu-weighted annual average NO_X emissions rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emissions limitations under 40 CFR Part 76.5, 76.6, or 76.7, except that for any early election units, the applicable emissions limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under each respective plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plans shall be final only when the Alabama Department of Environmental Management, Kentucky Department for Environmental Protection, and Memphis-Shelby County Health Department have also approved the averaging plans.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.</td></tr>
</table>

		2010	2011	2012	2013	2014
Unit 3	**SO_2 allowances, under Tables 2, 3, or 4 of 40**	6,531	6,531	6,531	6,531	6,531

	CFR part 73.					
	NO_X limit	Pursuant to 40 CFR Part 76, the Tennessee Department of Environment and Conservation approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2010, 2011, 2012, 2013, and 2014. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of **0.42 lb/MMBtu**. In addition, this unit shall not have an annual heat input greater than **12,773,319 MMBtu.** Under each plan, the actual Btu-weighted annual average NO_X emissions rate for the units in each plan shall be less than or equal to the Btu-weighted annual average NO_X emissions rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emissions limitations under 40 CFR Part 76.5, 76.6, or 76.7, except that for any early election units, the applicable emissions limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under each respective plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plans shall be final only when the Alabama Department of Environmental Management, Kentucky Department for Environmental Protection, and Memphis-Shelby County Health Department have also approved the averaging plans. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.				

		2010	**2011**	**2012**	**2013**	**2014**
Unit 4	**SO_2 allowances, under Tables 2, 3, or 4 of 40 CFR part 73.**	6,680	6,680	6,680	6,680	6,680
	NO_X limit	Pursuant to 40 CFR Part 76, the Tennessee Department of Environment and Conservation approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2010, 2011, 2012, 2013, and 2014. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of **0.42 lb/MMBtu**. In addition, this unit shall not have an annual heat input greater than **12,490,535 MMBtu**. Under each plan, the actual Btu-weighted annual average NO_X emissions rate for the units in each plan shall be less than or equal to the Btu-weighted annual average NO_X emissions rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emissions limitations under 40 CFR Part 76.5, 76.6, or 76.7, except that for any early election units, the applicable emissions limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under each respective plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plans shall be final only when the Alabama Department of Environmental Management, Kentucky Department for Environmental Protection, and Memphis-Shelby County Health Department have also approved the averaging plans. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.				

3. **Standard Requirements (40 CFR 72.9 and TAPCR 1200-3-30-.01(6)):** Included with permit application (see Attachment).

4. **Comments, Notes, and Justifications:** Affected units are four (4) coal fired boilers and three (3) combined cycle units.

5. **Permit Application and NO_X Compliance Plan:** Attached.

6. **Summary of Previous Actions and Present Action:**

Previous Actions:

1. Draft permit, including SO_2 compliance plan, issued for public comment: **August 5, 1997**

2. SO_2 portion of permit finalized and issued: **November 10, 1997**

3. Permit revised to include a draft nitrogen oxides Emissions Early Election Compliance Plan for Units 1, 2, 3, and 4, issued for public comment on the NO_X portion only: October 8, 1998

4. NO_X portion of permit finalized and issued. **April 1, 1999**

Present Action:

5. Draft renewal permit issued for public comment: **March 15, 2014**

Attachment:
Acid Rain Permit Application and
NO_X Compliance Plan

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

2009 DEC 17 PM 1:10

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☑ revised ☑ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
John Sevier	TN	3405

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
3	Yes
4	Yes
JCC1	Yes
JCC2	Yes
JCC3	Yes

EPA Form 7610-16 (rev. 07-08)

John Sevier
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

John Sevier
Facility (Source) Name (from STEP 1)

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

John Sevier
Facility (Source) Name (from STEP 1)

Recordkeeping and Reporting Requirements, Cont'd.

STEP 3, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

John Sevier
Facility (Source) Name (from STEP 1)

Effect on Other Authorities, Cont'd.

STEP 3, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

STEP 4
Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name John J. McCormick	
Signature [signature]	Date 12-15-09

2009 DEC 17 PM 1:10

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_X Compliance Plan

Page 1 of 2

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☑ New ☐ Revised

2009 DEC 17 PM 1: 14

STEP 1
Indicate plant name, State, and ORIS code from NADB, if applicable

Plant Name	State	ORIS Code
John Sevier	TN	3405

STEP 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 1	ID# 2	ID# 3	ID# 4	ID#	ID#
	Type T	Type T	Type T	Type T	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☑	☑	☑	☑	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging form)	☑	☑	☑	☑	☐	☐

Plant Name (from Step 1)	John Sevier	NO$_x$ Compliance - Page 2 Page 2 of 2

STEP 2, cont'd.

	ID# 1 Type T	ID# 2 Type T	ID# 3 Type T	ID# 4 Type T	ID# Type	ID# Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign & date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO$_x$ as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).
Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.
Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO$_x$ for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO$_x$ for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	John J. McCormick	
Signature		Date 12-15-09

EPA Form 7610-28 (12-03)

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_X Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11 2009 DEC 17 PM 1:14

Page 1

This submission is: ☑ New ☐ Revised

Page 1 of 4

STEP 1

Identify the units participating in this averaging plan by plant name, State, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation (ACEL) in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) ACEL	(c) Annual Heat Input Limit
Allen	TN	1	0.86	0.76	17,348,181
Allen	TN	2	0.86	0.76	15,500,918
Allen	TN	3	0.86	0.76	16,941,173
Bull Run	TN	1	0.40	0.63	59,269,756
Colbert	AL	1	0.50	0.48	9,479,205
Colbert	AL	2	0.50	0.48	10,155,383
Colbert	AL	3	0.50	0.48	11,500,927
Colbert	AL	4	0.50	0.48	11,587,558
Colbert	AL	5	0.50	0.45	28,464,183

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.5708	≤	**0.5713**

$$\frac{\sum_{i=1}^{n} (R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{Ii} \times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1;

R_{Ii} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

EPA Form 7610-29 (12-03)

Plant Name (from Step 1) **Tennessee Valley Authority System - Various Units**

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Cumberland	TN	1	0.68	0.56	77,769,426
Cumberland	TN	2	0.68	0.56	77,173,361
Gallatin	TN	1	0.45	0.29	15,485,326
Gallatin	TN	2	0.45	0.29	15,608,313
Gallatin	TN	3	0.45	0.34	18,717,826
Gallatin	TN	4	0.45	0.34	18,455,217
John Sevier	TN	1	0.40	0.42	12,648,030
John Sevier	TN	2	0.40	0.42	12,651,121
John Sevier	TN	3	0.40	0.42	12,773,319
John Sevier	TN	4	0.40	0.42	12,490,535
Johnsonville	TN	1	0.45	0.52	7,904,732
Johnsonville	TN	10	0.50	0.51	6,242,572
Johnsonville	TN	2	0.45	0.51	8,672,996
Johnsonville	TN	3	0.45	0.51	8,912,834
Johnsonville	TN	4	0.45	0.51	8,991,300
Johnsonville	TN	5	0.45	0.51	7,881,125
Johnsonville	TN	6	0.45	0.51	6,942,716
Johnsonville	TN	7	0.50	0.51	5,356,695
Johnsonville	TN	8	0.50	0.51	6,651,211
Johnsonville	TN	9	0.50	0.51	6,877,482
Kingston	TN	1	0.40	0.57	10,878,551
Kingston	TN	2	0.40	0.57	10,947,792
Kingston	TN	3	0.40	0.57	10,803,474
Kingston	TN	4	0.40	0.57	10,862,760
Kingston	TN	5	0.40	0.39	9,413,019
Kingston	TN	6	0.40	0.39	5,165,382

Plant Name (from Step 1) **Tennessee Valley Authority System - Various Units**

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Kingston	TN	7	0.40	0.39	6,110,364
Kingston	TN	8	0.40	0.39	4,203,972
Kingston	TN	9	0.40	0.50	13,971,884
Paradise	KY	1	0.86	0.90	48,926,900
Paradise	KY	2	0.86	0.90	45,893,042
Paradise	KY	3	0.86	0.90	66,121,361
Shawnee	KY	1	0.46	0.43	8,810,737
Shawnee	KY	2	0.46	0.43	7,664,953
Shawnee	KY	3	0.46	0.43	8,630,718
Shawnee	KY	4	0.46	0.43	8,578,830
Shawnee	KY	5	0.46	0.43	8,709,308
Shawnee	KY	6	0.46	0.43	9,212,743
Shawnee	KY	7	0.46	0.43	9,187,847
Shawnee	KY	8	0.46	0.43	9,041,547
Shawnee	KY	9	0.46	0.43	8,430,581
Widows Creek	AL	1	0.46	0.50	3,589,059
Widows Creek	AL	2	0.46	0.50	3,099,420
Widows Creek	AL	3	0.46	0.50	4,509,249
Widows Creek	AL	4	0.46	0.50	5,310,876
Widows Creek	AL	5	0.46	0.50	3,871,690
Widows Creek	AL	6	0.46	0.50	5,202,135
Widows Creek	AL	7	0.40	0.44	36,247,301
Widows Creek	AL	8	0.40	0.44	34,307,989

Plant Name (from Step 1) **Tennessee Valley Authority System - Various Units**

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year __________ through calendar year ____________ unless notification to terminate the plan is given.

☑ Treat this plan as **5** identical plans, each effective for one calendar year for the following calendar years: **2010, 2011, 2012, 2013, and 2014** unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	John J. McCormick	
Signature		Date 12-15-09

EPA Form 7610-29 (12-03)

TITLE V PERMIT STATEMENT

Company	**Tennessee Valley Authority**
Facility Name:	**Tennessee Valley Authority – John Sevier Combined Cycle and Fossil Plant**
City:	**Rogersville**
County:	**Hawkins**

Date Application Received:	**April 24, 2013**
Date Application Deemed Complete:	**April 24, 2013**

Emission Source Reference No.:	**37-0007**
Permit No.:	**567175**

INTRODUCTION

This narrative is being provided to assist the reader in understanding the content of the attached Title V operating permit. This Title V Permit Statement is written pursuant to Tennessee Air Pollution Control Rule 1200-3-9-.02(11)(f)1.(v). The primary purpose of the Title V operating permit is to consolidate and identify existing state and federal air requirements applicable to TVA John Sevier Fossil Plant and to provide practical methods for determining compliance with these requirements. The following narrative is designed to accompany the Title V Operating Permit. It initially describes the facility receiving the permit, then the applicable requirements and their significance, and finally the compliance status with those applicable requirements. This narrative is intended only as an adjunct for the reviewer and has no legal standing. Any revisions made to the permit in response to comments received during the public participation process will be described in an addendum to this narrative.

Acronyms

PSD - Prevention of Significant Deterioration
NESHAP - National Emission Standards for Hazardous Air Pollutants
NSPS - New Source Performance Standards
MACT - Maximum Achievable Control Technology
NSR - New Source Review

I. Identification Information

A. Source Description

Emission Source Number	Description
37-0007-01-04	Four (4) Coal Fired Boilers (removed from service or retired)
37-0007-05	Coal Handling Facility (removed from service)
37-0007-13	Dry Ash Handling System (removed from service)
37-0007-14	Combined/Simple-Cycle Turbines
37-0007-15	Natural Gas Fired Auxiliary Boiler
37-0007-16	Two Natural Gas Fired Heaters
37-0007-17	Mechanical-Draft Cooling Tower
37-0007-18	Emergency Fire Pump
37-0007-19	Two Distillate Oil Storage Tanks

B. Facility Classification

1. Attainment or Non-Attainment Area Location: The facility is located in an attainment area (Hawkins County) for the annual and 24-hour $PM_{2.5}$ standards. The facility is located in an attainment area for the 8-hour ozone standard.

2. This facility is located in a Class II area.

C. Regulatory Status

1. PSD/NSR: This facility is a major source for PSD.
2. Title V Major Source Status by Pollutant

Pollutant	Is the pollutant emitted?	If emitted, what is the facility's status? (Major Source or Non-Major Source)
PM	Yes	Major Source
PM_{10}	Yes	Major Source
SO_2	Yes	Major Source
VOC	Yes	Major Source
NO_X	Yes	Major Source
CO	Yes	Major Source
Individual HAP	Yes	Major Source
Total HAPs	Yes	Major Source
CO_2e	Yes	Major Source

3. MACT Standards for Sources contained in this Title V Application: 40 CFR 63 Subparts YYYY (Stationary Combustion Turbines) and DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters)

4. Program Applicability: Are the following programs applicable to the facility?

PSD: Yes

NESHAP: No

NSPS: Yes (40 CFR 60 Subparts Dc, IIII, and KKKK)

D. Permitting Activities since Original Permit Issuance: See Attachment A.

E. Permit Renewal Changes: See Attachment A.

II. Compliance Information

A. Compliance Status

Is this portion of the facility currently in compliance with all applicable requirements? yes
Are there any applicable requirements that will become effective during the permit term? no

III. Other Requirements

A. Emissions Trading: This facility is involved in several emissions trading programs (Acid Rain program, CAIR SO_2 and NO_X trading programs).

B. Acid Rain Requirements: This facility is subject to the requirements in Title IV of the Clean Air Act.

C. Prevention of Accidental Releases: This facility is not subject to the accidental release requirements of Section 112(r) of the Clean Air Act.

IV. Public Participation Procedures

Notification of this draft permit was mailed to the following environmental agencies:

1. EPA
2. North Carolina
3. Kentucky
4. Virginia

RESPONSE TO COMMENTS

General Information

Facility Name:	**Tennessee Valley Authority – John Sevier Combined Cycle and Fossil Plant**
Emission Source Reference No.:	**37-0007**
Permit No.:	**567175**
Date Application Received:	**April 24, 2013**
Date Application Deemed Complete:	**April 24, 2013**
Public Notice Date:	**March 15, 2014**
Public Hearing Date	**April 16, 2014**

The public notice for this permit was published in the Rogersville Review on March 15, 2014, and a public hearing for the proposed permit was held on April 16, 2014. There were no comments received during the public comment period, and there were no comments received at the public hearing.

Statement of Basis for 37-0007 Title V Operating Permit 560776
Attachment A: Modifications to Title V Permit since First Issuance

The purpose of this addendum is to address the changes made to this facility since issuance of Title V Operating Permit 548473. Specific changes are addressed in the following tables:

37-0007: Changes to Title V Operating Permit 548473 since First Issuance

Permit Modification	Issue Date	Condition or Section	Modification
Reopen for Cause		E3-6	The compliance method for visible emissions was changed from continuous opacity monitoring to Method 9 visible emissions evaluation, and the following language was removed from Condition E3-6: *Consistent with the provisions of Rule 1200-3-20-.06 of the Tennessee Air Pollution Control Regulations, no notice of violation shall be automatically issued for periods of visible emissions from this fuel burning installation that are in excess of the applicable visible emission standard so long as the total amount of time that the fuel burning installation is exceeding the applicable visible emission standard (excluding periods of permitted startup, permitted shutdown, or malfunction and periods when the fuel burning installation is not operating) is not in excess of two (2) percent of the total amount of time in a calendar quarter. This exemption from automatic issuance of a notice of violation is applicable provided that good operational and maintenance practices are utilized for both the fuel burning equipment and the associated air pollution control equipment, the required ninety-five (95) percent operational availability of the opacity monitoring system is maintained, and that no more than one exceedance of greater than twenty-four (24) hours duration occurs per calendar year.* *Written responses to the quarterly reports of excess emissions shall constitute prima facie evidence of compliance with the applicable visible emission standard. For purposes of annual certification of compliance with the applicable visible emissions condition, the acceptance, by the Division, of the quarterly reports of excess emissions shall be the basis of said certification.*
		Attachment 7	Added NO_X Budget Permit.

37-0007: Changes Made in Title V Renewal Permit 560776

Condition	Change (Title V Renewal Permit)
A19, Attachment 7	Added new Acid Rain permit.
B5	Condition B5(d) was revised to add the underlined language: **(d)** The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in B5(b) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion* or exceedance** as defined below occurred; and
C1	Condition C1 was revised to add the underlined language: **Operational flexibility changes.** The source may make operational flexibility changes that are not addressed or prohibited by the permit without a permit revision subject to the following requirements: **(a)** The change cannot be subject to a requirement of Title IV of the Federal Act or Chapter 1200-3-30. **(b)** The change cannot be a modification under any provision of Title I of the federal Act or Division 1200-3. **(c)** Each change shall meet all applicable requirements and shall not violate any existing permit term or condition. **(d)** The source must provide contemporaneous written notice to the Technical Secretary and EPA of each such change, except for changes that are below the threshold of levels that are specified in Rule 1200-3-9-.04. **(e)** Each change shall be described in the notice including the date, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change. **(f)** The change shall not qualify for a permit shield under the provisions of part 1200-3-9-.02(11)(e)6. **(g)** The permittee shall keep a record describing the changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes. The records shall be retained until the changes are incorporated into subsequently issued permits.
C2	Condition C2(b) was revised to add the underlined language: **(b)** The written notification must be signed by a facility Title V responsible official and include the following: **1.** brief description of the change within the permitted facility; **2.** specifies the date on which the change will occur; **3.** declares and quantifies where possible any change in emissions; **4.** declares any permit term or condition that is no longer applicable as a result of the change; and **5.** declares the requested change is not a Title I modification and will not exceed allowable emissions under the permit.
D1	Added language for certificate of validation.
E1	Updated fee requirements to allow payment based on actual emissions.
E2-1(a) E2-1(b)	Updated quarterly and semiannual reporting requirements.
E2-1(c)	Condition E2-1(c)(4) was revised to add the underlined language: **(4)** The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in E2-1(b)(2) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an *excursion or **exceedance as defined below occurred; and
E2-2	Added new condition to address general requirements for data entry.
E2-4	Added new condition to address general requirements for opacity monitoring. The fugitive dust requirements from Condition E6-1 of the previous Title V permit were deleted, and the compliance method was moved to Condition E2-4. The visible emission limits in Condition E6-1 of the previous permit were deleted because they duplicate the requirements of Condition D7(b).
E2-5	Added updated requirements for ambient SO_2 monitoring to reflect changes in TAPCR 1200-03-14. This condition replaces Condition E6-2 of the previous permit, which was deleted from the renewal.
Section E3	Permit conditions were renumbered, added, or deleted as follows:

37-0007: Changes Made in Title V Renewal Permit 560776

Old Permit Condition	New Permit Condition
E3-1	E3-1
E3-2	E3-2
E3-3	E3-3
E3-4	E3-4
E3-5	E3-5
E3-6	E3-8
E3-7	E3-9
E3-8	E3-10
E3-9	E3-6
E3-10	E3-7
E3-11	E3-11
E3-12	E3-13
E3-13	Condition deleted. Requirements were combined with Condition E3-2 in new permit.
E3-14	E3-12
E3-15	Condition deleted. Requirements were combined with Condition E3-13 in new permit.
E3-16	Condition deleted. Requirements were combined with Condition E3-13 in new permit.
N/A	E3-14 (new condition)

Condition	Change (Title V Renewal Permit)
E3-1	Deleted Acid Rain Program and NO_X Budget Trading Program requirements from this condition.
E3-2	Added recordkeeping requirements for used oil and nonhazardous solvents (these requirements were deleted from Condition E3-13 of the old permit).
E3-4, Attachment 2	Updated compliance method language. Added Compliance Assurance Monitoring requirements for opacity monitoring. Updated language addressing exceedances of the de minimis criteria of TAPCR 1200-03-20.
E3-6	Updated operational availability requirement for COMS from 90% per month to 95% per quarter (updated condition matches TACPR requirement). Deleted the requirement to use backup monitoring if the SO2 monitoring system is inoperative for more than 7 days.
E3-8	Removed COMS "monitoring method".
E3-10	Amended as follows: "Each in-stack opacity monitoring system for this fuel burning installation shall be fully operational for at least ninety-five (95) percent of the operational time of the monitored units during each ~~month of the~~ calendar quarter."
E3-13	The reporting requirements from Conditions E3-15 and E3-16 of the old permit were combined into this condition.
E3-14, Attachment 8	Added new condition to address CAIR requirements. Added CAIR permit.
Section E5, Section E6	Emission source 37-0007-13 was moved from Section E6 of the previous permit to Section E5. General facility ambient air monitoring (37-0007-99) was moved from Section E7 of the previous permit to Section E6. Emission source 37-0007-12 (railcar thawer, Section E5 of previous permit) was removed from the permit.
E4-1, E5-3	The following language was removed (moved to Condition E2-4): *"If the magnitude and frequency of excursions reported by the permittee in the periodic monitoring for emissions is unsatisfactory to the Technical Secretary, this permit may be reopened to impose additional opacity monitoring requirements."*
Response to Comments	Comments on the draft permit were submitted by the Environmental Integrity Project on behalf of the Environmental Integrity Project, the Southern Environmental Law Center, and the Tennessee Environmental Council. These comments and Tennessee's responses are included with the original statement of basis for Title V Operating Permit 560776.

37-0007: Changes Made in Title V Renewal Permit 567175

Condition	Change (Title V Renewal Permit)
E1	Updated fee emissions to reflect the addition of combined cycle operations, retirement of two coal-fired units, removal from service of two coal-fired units and associated coal and materials handling operations.
E2-1	Updated reporting requirements
E2-2	Added 10% opacity limit for the entire facility.
E2-3	Added facility-wide recordkeeping requirements.
E2-4	Added routine maintenance requirement for air pollution control devices.
E2-5	Added facility-wide emission limits for PSD avoidance
E2-6	Added CAM (40 CFR 64) exemption.
E2-7	Added language to address consent decree. Removed coal-fired boilers and associated equipment as follows:

Plant	Unit	Control Requirement	Effective Date
37-0007-01-04	Boilers 1 and 2	Retired	December 31, 2012
37-0007-01-04	Boilers 3 and 4	Removed from Service	December 31, 2012
37-0007-05	Coal handling	Removed from Service	December 31, 2012
37-0007-13	Dry ash handling	Removed from Service	December 31, 2012

Condition	Change (Title V Renewal Permit)
Section E3	Added requirements for combined cycle gas plant.
Section E4	Added requirements for gas-fired auxiliary boiler.
Section E5	Added requirements for gas-fired heaters.
Section E6	Added requirements for cooling tower.
Section E7	Added requirements for emergency fire pump engine.
Section E8	Added requirements for distillate oil storage tanks.

Changes to Title V Renewal Permit 567175 since Issuance			
Permit Modification	**Issue Date**	**Condition or Section**	**Modification**
Significant Modification #1 (SM1)	Pending	**General Information**	This modification changes the facility status from a major source of hazardous air pollutant (HAP) emissions to an area source. The change in category status is a result of the removal of coal-fired boilers 1-4 and associated coal and ash handling equipment. This modification also removes consent decree requirements for the facility, since the units subject to the consent decree have been removed.
		Cover Page, E2-8	Updated facility description and address. Moved Responsible Official and technical contact from the cover page to new condition E2-8.
		A12	Updated A12(a) to clarify the deadlines for submittal of a renewal application.
		B5, E2-1(b)	Removed the requirement for the ACC to state whether compliance method provide continuous or intermittent data (underlying applicable requirement no longer exists). Updated citation for underlying applicable requirement.
		E2-6	Added mailing address and e-mail address for Johnson City Environmental Field Office.
		E1	Updated annual accounting period dates and removed allowable emissions from fee table.
		E2-7	Removed Consent Decree requirements. Boilers 1-4 and associated coal and ash handling equipment were removed from the site.
		E3-10(d)	Corrected a typographical error in a reporting condition, as follows: "(d) When the system has ~~not~~ been inoperative, repaired, or adjusted, such information shall be included in the report."
		E3-11, Attachment 5	Deleted CAIR requirements and CAIR permit.
		E3-12, Attachment 4	Added Transport Rule (CSAPR) requirements. Moved Acid Rain Permit from Attachment 4 to Attachment 5.
		E4-7, E5-5	Updated Boiler MACT requirements to show that the affected source is not subject to 40 CFR 63 Subpart DDDDD (removal of coal-fired boilers makes this facility an area source of HAP). This condition also designates the affected sources as "gas-fired boilers" that are not subject to any requirements under 40 CFR 63 Subpart JJJJJJ.
		Public Comments	The public notice for this modification will be published in the *Rogersville Review*. Any comments received during the public comment period will be noted here.