West Virginia Department of Environmental Protection

Harold D. Ward
Cabinet Secretary

Construction Permit

R14-0038

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 CSR 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:
Mountain State Clean Energy LLC
061-00134
Maidsville

____
Laura M. Crowder
Director, Division of Air Quality

Issued: DRAFT

Facility Location:	1375 Fort Martin Road Maidsville, Monongalia County, West Virginia 26541
Mailing	Same as Above
Facility Description:	Natural gas fired Electric Generating Unit (EGU)
NAICS Codes:	221112
UTM Coordinates:	580.6 km Easting • 4,306.9 km Northing • Zone 17
Permit Type:	Construction of a PSD Major Source
Description of Change:	This action is for the construction of the facility, which includes two combustion turbines with heat recovery steam generators, two fuel gas heaters, cooling tower, one auxiliary emergency generator, one fire water pump and an ammonia storage vessel.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

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1.0. Emission Units

<table>
<tr><th>Emission Unit ID</th><th>Emission Point ID</th><th>Emission Unit Description</th><th>Year Installed</th><th>Design Capacity</th><th>Control Device</th></tr>
<tr><td>CT-1</td><td rowspan="2">CT-1</td><td>Combustion Turbine (CT) No.1</td><td>2025</td><td>3,875 MMBtu/hr</td><td rowspan="2">DLNC, SCR, Ox Cat</td></tr>
<tr><td>HRSG1</td><td>Heat Recovery Steam Generator (HRSG) with Duct Burners No. 1</td><td>2025</td><td>586 MMBtu/hr</td></tr>
<tr><td>CT-2</td><td rowspan="2">CT-2</td><td>Combustion Turbine (CT) No.2</td><td>2025</td><td>3,875 MMBtu/hr</td><td rowspan="2">DLNC, SCR, Ox Cat</td></tr>
<tr><td>HRSG2</td><td>Heat Recovery Steam Generator (HRSG) with Duct Burners No. 2</td><td>2025</td><td>586 MMBtu/hr</td></tr>
<tr><td colspan="6">The CTs proposed for the project are General Electric (GE) 7HA.03 turbine or equivalent (i.e., Mitsubishi Hitachi Power System M501JAC series). Each CT will utilize inlet air cooling and wet compression. Emissions from each turbine will be controlled using dry low-NO_X (DLN) combustion and selective catalytic reduction (SCR). Each combustion turbine generator (CTG) will have a nominal electrical output of 400 MW. Each turbine will be connected to a heat recovery steam generator (HRSG). Steam generated in the three HRSGs will be routed to a common steam turbine (ST), with a nominal generating capacity of 430 MW. The total nominal electrical generating capacity for facility is 1300 MW. The nominal design heat input rate to each turbine is 3,875 MMBtu/hr when firing natural gas, based on an ambient air temperature of 54 degrees Fahrenheit (°F), evaporative cooling and wet compression, 69 percent (%) relative humidity, 14.1 pounds per square inch (psi) pressure, the lower heating value (LHV) of the fuel, and 100% load. Each HRSG will have a stack height of 180 ft and an inner stack diameter of 23 ft. Each stack will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NO_X and CO emissions as well as flue gas oxygen content. {Note: Actual heat input rate varies depending upon gas turbine characteristics, ambient conditions, and inlet air cooling.}</td></tr>
<tr><td>FGH-1</td><td>FGH-1</td><td>Fuel Gas Heater No. 1</td><td>2025</td><td>7.0 MMBtu/hr</td><td>LNB</td></tr>
<tr><td>FGH-2</td><td>FGH-2</td><td>Fuel Gas Heater No. 2</td><td>2025</td><td>7.0 MMBtu/hr</td><td>LNB</td></tr>
<tr><td>EG-01</td><td>EG-01</td><td>Emergency Generator.
Lean burn 4-stoke, reciprocating, compression ignition engine (RICE)</td><td>2025</td><td>2,100 bhp</td><td>None</td></tr>
<tr><td>FWP-1</td><td>FWP-1</td><td>Fire Water Pump No. 1
RICE</td><td>2025</td><td>240 bhp</td><td>None</td></tr>
<tr><td>DT-1</td><td>DT-1</td><td>Emergency Generator Fuel Storage Tank</td><td>2025</td><td>300 gallons</td><td>Ox Cat</td></tr>
<tr><td>DT-2</td><td>DT-2</td><td>Firewater Pump Fuel Storage Tank</td><td>2025</td><td>125 gallons</td><td>Ox Cat</td></tr>
<tr><td>AA-1</td><td>AA-1</td><td>Aqueous Ammonia Storage Tank No. 1</td><td>2025</td><td>60,000 gallons</td><td>None</td></tr>
<tr><td>AA-2</td><td>AA-2</td><td>Aqueous Ammonia Storage Tank No. 2</td><td>2025</td><td>60,000 gallons</td><td>None</td></tr>
<tr><td>WCT-1</td><td>WCT-1</td><td>Mechanical Draft Cooling Tower</td><td>2025</td><td>270,000 gal/min</td><td>Demisters</td></tr>
<tr><td>EC-1</td><td>N/A</td><td>Reciprocating Compressor No. 1
Electrically Driven</td><td>2025</td><td>2,750 hp</td><td>None</td></tr>
<tr><td>EC-2</td><td>N/A</td><td>Reciprocating Compressor No. 2
Electrically Driven</td><td>2025</td><td>2,750 hp</td><td>None</td></tr>
</table>

DLNC – Dry Low NOx Combustion
LNB – Low NO_x Burner
SCR – Selective Catalytic Reduction to control oxides of nitrogen emissions.
Ox Cat – Oxidation Catalyst to control carbon monoxide and VOC emissions.

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CSR	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
dscm	Dry Standard Cubic Meter
FOIA	Freedom of Information Act
GHG	Greenhouse Gases
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr	Pounds per Hour
LDAR	Leak Detection and Repair
M	Thousand
MACT	Maximum Achievable Control Technology
MDHI	Maximum Design Heat Input
MM	Million
MMBtu/hr *or* **mmbtu/hr**	Million British Thermal Units per Hour
MMCF/hr *or* **mmcf/hr**	Million Cubic Feet per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 µm in diameter
PM_{10}	Particulate Matter less than 10µm in diameter
ppb	Pounds per Batch
pph	Pounds per Hour
ppm	Parts per Million
ppm_v	Parts per Million by Volume
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*; and

2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration.*

2.4. Term and Renewal

2.4.1. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R14-0038, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.10 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 CFR Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon 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 this permit;

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

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, 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.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. 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; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

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

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 CFR § 61.145, 40 CFR § 61.148, and 40 CFR § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 CFR § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 CFR Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

    1. The permit or rule evaluated, with the citation number and language;
    2. The result of the test for each permit or rule condition; and,
    3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Said records shall be maintained on site or in a readily accessible off-site location maintained by the permittee for a period of five (5) years. Said records shall be readily available to the Secretary of the Division of Air Quality or his/her duly authorized representative for expeditious inspection and review. Any records submitted to the agency pursuant to a requirement of this permit or upon request by the Secretary shall be certified by a responsible official. Where appropriate, the permittee may maintain records electronically. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.4.3. The permittee shall install and maintain an industrial fence around this permitted facility as outlined in the March 14, 2021, submittal of the Prevention of Significant Deterioration Air Quality Dispersion Modeling Report. This industrial fence shall be constructed in such a manner to prevent the general public from accessing this permitted facility.

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class or by private carrier with postage prepaid to the address(es), or submitted in electronic format by email as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:
Director
WVDEP
Division of Air Quality
601 57th Street
Charleston, WV 25304-2345

US EPA:
Section Chief
U.S. Environmental Protection Agency, Region III
Enforcement and Compliance Assurance
Division Air Section (3ED21)
1650 Arch Street
Philadelphia, PA 19103-2029

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov

[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status Reports, Initial Notifications, etc.

3.5.4. Operating Fee

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Specific Requirements for Combustion Turbines (CT-01 and CT-02)

4.1. Limitations and Standards

4.1.1. This permit allows the permittee to construct either two GE 7HA.03 combustion turbines or two MHPS M501JAC combustion turbines. The following conditions and requirements are specific to Combustion Turbines #1 and #2 (ID CT-01 & CT-02):

a. Emissions from each CT/HRSG shall not exceed the following:

Table 4.1.1.a. BACT & NSPS Limits for CT-01 & CT-02				
Pollutant	**Emission Standard [a]**	**Basis**	**Compliance Method [b]**	**Averaging Time**
NOx	2.0 ppmdv @15% O_2	BACT	CEMS	3-hour rolling average
	0.43 lb/MWh gross	NSPS KKKK		30-operating day rolling avg.
CO	2.0 ppmdv @15% O_2	BACT	CEMS	3-hr block avg.
VOC	1 ppmdv @15% O_2 (w/o duct firing)	BACT	Initial stack test, Subsequent when required	Three -1hr runs
	2 ppmdv @15% O_2 (with duct firing)			
$PM_{10}/PM_{2.5}$	0.006 lb/MMBtu	BACT	Initial stack test, Subsequent when	Avg. of three 4-hr runs
PM	0.05 lb/MMBtu	Rule 2[g]	Initial test when DB capacity factor is greater than 50%	Avg. of three 2-hr runs
SO_2	0.4 gr Sulfur/100 scf NG	Permit Limit	Fuel Sampling & Analysis	N/A
	0.060 lb SO_2/MMBtu[d] Or 20 gr Sulfur/100 scf NG[d]	NSPS KKKK		
H_2SO_4	0.4 gr Sulfur/100 scf	BACT		
GHG (CO_{2e})	See Condition 4.1.2.	BACT		12-operating month rolling avg.
		NSPS TTTT	Fuel Usage and default factors for the Energy Output Standard or Fuel	12-operating month rolling avg.

	1,000 lb/MWh gross or 120 lb/MMBtu		Purchase Records for Heat input standard	N/A

a. NOx, CO, and VOC concentration emission standards are expressed in parts per million by volume, dry, corrected to 15 percent oxygen, abbreviated as ppmvd @15% O_2.
b. CEMS means continuous emissions monitoring system.
c. Lb/MMBtu limits are based on higher heating value (HHV) of the fuel unless otherwise specified.
d. The SO_2 standard of Subpart KKKK is more stringent than 45 CSR §10-3.7.
e. The fuel sulfur specifications combined with the efficient combustion design and operation of the combustion turbines represent BACT for H_2SO_4 and SO_2 emissions. Compliance with the fuel specifications and CO standards limit shall serve as indicators of good combustion.
f. GHG monitoring shall be in accordance with 40 CFR 75, which includes options for continuous monitoring of fuel use combined with the use of emissions factors for GHGs, or the use of a continuous emissions monitor for CO_2. Calculations of CO_2e emissions shall use the 100-year global warming potential values listed in Table A-1 to Subpart A of 40 CFR 98 (e.g., 1 for CO_2, 25 for CH_4 and 298 for N_2O). The GHG BACT limit applies to the 2-on-1 combined cycle unit as an aggregate limit. The GHG BACT limit in Condition 4.1.2. applies during all operation.
g. The NSPS Subpart KKKK – NOx and SO_2 and Subpart TTTT CO_2 standard applies during all periods of operation.
- The Subpart KKKK limit of 0.43 lb of NOx/MW is based on a 30-operating day rolling average.
- The Subpart TTTT limit of 1,000 lb/MWh applies if the CT supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and 3-year rolling average basis and combusts more than 90% natural gas on a 12-operating-month rolling average basis (baseload). *{Note: This is the most likely operating scenario for the permitted CTs}*
- If the CT supplies its design efficiency times its potential electric output or less as net-electric sales on either a 12-operating-month or a 3-year rolling average basis, The NSPS GHG limit is given in Table 2 of Subpart TTTT. *{Permitting note: This limit is most likely to apply to simple-cycle or peaking units and is unlikely to apply to a combined-cycle unit.}*
- If the CT combusts less than 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis, the GHG limit is given in Table 2 of Subpart TTTT and 40 CFR 60.5525.

g. 45 CSR 2-4.1.a.

b. The mass emission rates from CT-01 and CT-02 shall not exceed the manufacturer's specific limits in the following table. These limits apply at all times, except during startups and shutdowns.

Table 4.1.1.b. OEM Specific Mass Emission Limits

Pollutant	OEM/Model	Limit (lb/hr)	Averaging Period	Compliance Method
NO_x	GE 7HA.03	34.09[2]	Rolling 3-hour average	Continuously w/CEMs
	MHPS M501JAC	32.09[2]		
CO	GE 7HA.03	20.76[2]	Rolling 3-hour average	Continuously w/CEMs
	MHPS M501JAC	19.54[2]		
VOC	GE 7HA.03	11.89[2]	3-hour average	Initial & Subsequent Testing
	MHPS M501JAC	11.19[2]		
SO_2	GE 7HA.03	6.02	Operating Day average	Fuel Analysis and fuel usage
	MHPS M501JAC	5.00		

$PM_{10}/PM_{2.5}$[1]	GE 7HA.03	23.36	12-hour average	Initial & Subsequent Testing
	MHPS M501JAC	25.32		
H_2SO_4	GE 7HA.03	4.28	3-hour average	Initial & Subsequent Testing
	MHPS M501JAC	2.91		

1- PM_{10} and $PM_{2.5}$ emissions shall include both fractions (condensable and filterable fractions) of PM.
2 – These limits do not apply during hours that either when a unit startup or shutdown occurred within the hour.

The emission limit in the above table shall be corrected to zero oxygen content using the appropriate method(s) outline U.S. EPA Method 19.

c. At times when the duct burner is firing, visible emissions from the corresponding emission point associated with the duct burner shall not be greater than ten (10) percent opacity based on a six-minute average.
[45 CSR §2-3.1.]

d. Hazardous air pollutants (HAPs) from each CT/HRSG shall not exceed the following:

i. Formaldehyde emissions from the combustion turbine of the emission unit shall not exceed 0.85 pound per hour on a 3-hour average basis or 91 ppbvd at 15% percent oxygen. The formaldehyde limit shall apply at all times, excluding startups and shutdowns. Startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle mode, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. For combined cycle mode, startup ends when the stationary combustion turbine has reached stable operation or after 3 hours, whichever is less.

ii. Combined HAPs from each unit, which includes formaldehyde emissions, shall not exceed 2.67 pounds per hour on a 3-hour average basis.

e. Annual NO_x emissions from each of emission points CT-01 and CT-02 shall not exceed 158.6 tons per year. Compliance with this limit shall be determine the monthly NO_x rate in terms of tons per month using the CEMS emission data and the determine the 12-month rolling total by the 15th of the preceding month. NO_x emissions shall be determined by taking the sum of all operating hour of the respective month of the product of the hourly NO_x rate in terms of lb/MMBtu by the hourly heat input rate in terms of MMBtu/hr for each unit.

f. Annual carbon dioxide emissions from each emission points CT-01 and CT-02 shall not exceed 136.9 tons per year. Compliance with this limit shall be determine the monthly CO rate in terms of tons per month using the CEMS emission data and the determine the 12-month rolling total by the 15th of the preceding month.

g. Annual volatile organic compound emissions from each emission points CT-01 and CT-02 shall not exceed 70.2 tons per year. Compliance with this limit shall be determine the monthly VOC rate in terms of tons per month using the CEMS emission data, correlation analysis between CO to VOCs, if determined to be valid, or the most recent testing data and the determine the 12-month rolling total by the 15th of the preceding month.

h. Annual particulate matter less than ten microns and particulate matter less than 2.5 microns emissions from each emission points CT-01 and CT-02 shall not exceed 101.2 tons per year. Compliance with this limit shall be determine the monthly PM_{10} and $PM_{2.5}$ rates in terms of tons per month using the $PM_{2.5}$ emission and actual operational data and the determine the 12-month rolling total by the 15th of the preceding month.

i. Annual sulfur dioxide emissions from emission points CT-01 and CT-02 shall not exceed 19.9 tons per year. Compliance with this limit shall be determine using the monthly sulfur dioxide emission from each unit (combustion turbine), which shall include the respective duct burner, and the determine the 12-month rolling total by the 15th of the preceding month. Such determinations shall utilize the fuel monitoring as required in Conditions 4.2.1. and 4.2.3.

4.1.2 GHG BACT for CT-01 and CT-02: CO_2e emissions from each of the combustion turbine (CT-01 and CT-02), providing for incremental degradation of the units, shall not exceed the following limits based on degradation period:

a. The following limits apply to the GE 7HA.03 combined cycle combustion turbine.

Degradation Period	Applicable limit in lb CO_2e/MWh gross output
Years 1-6	852
Years 7-12	869
Years 13-18	886
Years 19-24	903
Years 25-30	921
Years 31 and later	939

b. The following limits apply to the MHPS M501JAC combined cycle combustion turbine.

Degradation Period	Applicable limit in lb CO_2e/MWh gross output
Years 1-6	824
Years 7-12	840
Years 13-18	857
Years 19-24	874
Years 25-30	891
Years 31 and later	908

CO_2e within this condition shall include all six greenhouse gases as defined in 45 CSR §§14-2.80.

For the purposes of determining which limit is applicable, Year 1 begins upon commencement of commercial operation and ends on December 31 of the first full calendar year after that date. Each limit increments on January 1 of the respective year. For example, if the facility commences commercial operation on April 15, 2025, Year 1 begins on April 15, 2025, and ends on December 31, 2025. Year 7 begins, and the increased limit becomes effective, on January 1, 2032.

Compliance with the applicable limit shall be calculated monthly on a 12- month rolling basis by summing the total mass of the CO_2 emissions, in terms of lb of CO_2, during the month divided by total sum of the . Compliance may be determined each month by summing the calculated CO_2e emissions from the combustion turbine generators (CT-1 and CT-2) during the previous 12 months and dividing that value by the sum of the gross electrical energy output over that same period.

The above limits only apply at initial startup of the unit and at times when the unit meet the criteria of baseload unit as defined in Subpart TTTT of 40 CFR 60. For times when the unit(s) do not meet the criteria for a baseload unit, the unit shall not emit more than 120 lb CO_2e per MMBtu on a 12-month rolling average basis.
[45 CSR §14-8.3.]

4.1.3 The Primary NO_X, CO, and VOC BACT limits Set forth in Section 4.1.1. and 4.1.4 through 4.1.6 apply at all times, except during startup and shutdown conditions. Startup and shutdown operating scenarios for the combustion turbine generators (CT-01, and CT-02) are defined as follows:

a. Startup periods are defined as the time from combustion turbine (CT) ignition to the time that the HRSG stack NO_x and CO steady state emissions are in compliance with the short-term limits in Table 4.1.1.a. Steady state emissions shall mean when the unit is in compliance with both pollutants in terms of the limits in Table 4.1.1.a. for one quadrant of an hour (15-minute block) where the instrument measured a value at or less than the concentration limit in Table 4.1.1.a. The end of time of startup shall be the time at the beginning of the 15-minute block in which steady state emissions occurred.

b. For this permit, shutdown is defined as the time when the CT fall below 50 percent load and the HRSG stack NO_x and CO steady state emission are not in compliance with either of these pollutants short-term limits in Table 4.1.1.a. Shutdown ends either when the fuel flow to the unit is at zero and the HRSG stack NOx and CO are zero or once the unit reaches the HRSG stack NOx and CO steady state emissions are in compliance with the short-term limits in Table 4.1.1.a. for at least on 15-minute block for both pollutants then shutdown end time is time at the beginning of this 15-minute block of steady state emissions.

c. The permittee shall operate the Continuous Emission Monitoring System (CEMS) during all periods of startup and shutdown events.

d. Emissions during these events shall not exceed the following limits on a 30-day rolling total on a per CT and manufacturer basis:

   i. NOx emissions shall not exceed 2.68 tons for the MHPS M501JAC and 2.97 tons for the GE 7HA.03.

   ii. CO emissions shall not exceed 6.05 tons for the MHPS M501JAC and 11.36 tons for the GE 7HA.03.

   iii. VOC emissions shall not exceed 4.22 tons for the MHPS M501JAC and 3.87 tons for the GE 7HA.03.

   iv. PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.05 tons for the MHPS M501JAC and 0.28 tons for the GE 7HA.03.

e. No hour during any operating day that either a startup or shutdown event occurs within shall not exceed the following emission rates:

   i. NOx emissions shall not exceed 273.4 pounds per hour.

   ii. CO emissions shall not exceed 1,527.4 pound per hour.

   An hour is the 60-minute period beginning at the top of each hour (e.g., hour starts at 0:00:00 and ends at 0:59:59). Compliance with these limits shall include all emissions that occur within the hour regardless of if the unit experience a startup event and began operating at normal load conditions within the hour.

f. At no time shall both CTs be engaged in any SUSD event concurrently.

g. During startup and shutdown, the combustion turbine generator SCR system, including ammonia injection, and oxidation catalyst shall be operated in a manner to minimize emissions, as technologically feasible, and following the SCR manufacturer's written protocol or best engineering practices for minimizing emissions. Where best practices are used, the permittee shall maintain written documentation explaining the sufficiency of such practices. If such practices are used in lieu of the manufacturer's protocol, the documentation shall justify why the practices are at least equivalent to manufacturer's protocols with respect to minimizing emissions.

4.1.4. *BACT Control Devices and/or Measures:* The permittee shall install or implement the following devices or measures in accordance with the following.

a. The permittee shall install, operate, and maintain the dry-low NO_X (DLN) combustion system or its equivalent on each CT to control NO_X emissions from the CT when firing natural gas. Prior to the initial emissions performance tests required for the CT, the DLN combustors or its equivalent and automated gas turbine control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or determined best practices.

b. After completing the steam blows or after the first 50 hours of operation of the unit, whichever comes first, the permittee shall install the catalyst beds for the SCR control devices and tune the device to comply with the NO_x limits in Condition 4.1.1.a. and the ammonia slip limit in Condition 4.1.3.c.
[40 CFR §60.4333(a)]

c. The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each gas turbine. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping, and other ancillary equipment. The SCR system shall be designed, constructed, and operated to achieve compliance the NOx BACT limit for NO_X emissions with a concentration of ammonia (ammonia slip) of no greater than 5 ppm correct to 15% oxygen on a 24-hour averaging period basis from the outlet of the SCR.
[45 CSR §14-8.3. and 40 CFR §60.4333(a)]

e. To comply with PM, PM_{10}, $PM_{2.5}$, and H_2SO_4 BACT limits in Condition 4.1.1.a., each turbine shall only be fired with pipeline-quality natural gas with a total sulfur content of no greater than 0.4 grains per 100 cubic feet of gas.
[45 CSR §14-8.3]

f. The permittee shall install, operate, and maintain each CT and duct burner using good combustion practices as part of the BACT level of control for PM, PM10, PM2.5, CO, and VOC emissions.

Operation and maintenance manual for the specific CT shall be maintained on site for the life of the unit. Once every calendar year, the permittee shall review all good combustion practice changes issued by the original equipment manufacturer (OEM) and update the operation and maintenance manual as applicable. Should the permittee elect not to implement such change issued by the OEM, the permittee shall keep record with the operation and maintenance manual as to why the change was not implemented.

For demonstration of good combustion practices, the permittee shall always operate CT with the OEM's proprietary combustion system excluding SUSD events and during equipment performance demonstration that the OEM's combustion system needs to be disabled to conduct a valid demonstration and conduct seasonal tuning of the unit to optimize the formation of NO_x while minimizing the formation of CO.

Seasonal tuning shall be conducted at least twice a year with a minimum of 4 months between successful tunings. The permittee shall conduct tuning in accordance with the manufacturer's written procedure with focus to optimize the formation of NO_x to lowest level corrected to 15% O_2 while minimizing the formation of CO. At times when the annual duct burner utilization is greater than 50%, the duct burner tuning shall be conducted with the focus of optimizing the formation of NO_x to lowest level while minimizing the formation of CO. The permittee may forgo conducting seasonal tuning if good combustion practices and the limits for NOx and CO identified herein are being maintained.

At times when either key operating parameter(s) does not indicate good combustion practices are being achieved and the NO_x and CO is greater than limits stated in Table 4.1.1.a., the permittee shall initiate corrective action to restore good combustion practices within 48-hours of not achieving good combustion practices. The permittee shall restore good combustion practices in a timely fashion which shall not exceed after the restart of the next planned maintenance outage of the respective CT. Records of this corrective action shall be maintained in accordance with Condition 3.4.1.
[45 CSR §14-8.3]

g. The permittee must operate and maintain each 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.
[40 CFR §60.4333(a)]

h. Each combustion turbine shall be equipped with an oxidation catalyst air pollution control device. The oxidation catalyst shall be installed, maintained, and operated as outlined in Condition 4.1.5.
[45 CSR §14-8.3]

4.1.5. Requirements of the Oxidization Catalysts for CT-01 and CT-02.

a. The temperature of the exhaust entering the catalyst must be within the operating range indicated by the catalyst manufacturer on a four (4) hour rolling average basis. The temperature readings recorded during start-up and shutdown event as defined in Condition 4.1.3 shall not be used in determining the four-hour rolling average.

b. The pressure drop across the catalyst shall be no greater than 2 inches above the measured pressure drop at initial start-up with the turbine operating at 100% load ($\pm$ 10%) or as otherwise specified by the catalyst manufacturer.

c. The permittee shall wash or replace the catalyst in accordance with the manufacturer's guidance/recommendation intervals or develop and implement a means to determine when the catalyst is no longer capable of achieving the CO BACT limit in Condition 4.1.1.a.

4.1.6. The emission units CT-01 and CT-02, which includes the respective duct burner, is restricted to combusting pipeline quality natural gas (gaseous fuel). This pipeline quality natural gas shall not have a sulfur content of greater than 0.4 grains per 100 cubic feet of gas.
[45 CSR §10-3.7, and 40 CFR §63.7575]

4.1.7. The permittee shall submit a complete Acid Rain permit application governing such unit to the Director at least 24 months before date on which the unit commences operation.
[40 CFR §72.30(b)(2)(ii) and 45 CSR §33-4]

4.1.8. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.10.]

4.2. Monitoring Requirements

4.2.1.1 CEMS: Subject to the following, the permittee shall install, calibrate, operate, and maintain a CEMS to measure and record the emissions of NO_X and CO from the combustion turbines in terms of the applicable limitations in this permit. The monitoring system shall be installed and functioning within the required performance specifications by the time of the initial compliance demonstration.

a. NO_X Monitor: Each NO_X monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.
[40 CFR §60.4345(a) and 45 CSR §14-7.7]

b. CO Monitor: Each CO monitor shall be certified pursuant to Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The CO CEMS shall be installed, evaluated, and operated according to the monitoring requirements in 40 CFR 60.13. Quality assurance procedures shall conform to the requirements of Appendix F of 40 CFR 60. The annual required RATA tests required for the CO monitor shall be performed using EPA Method 10, 10A, 10B in Appendix A of 40 CFR 60.
[45 CSR §14-7.7]

c. Diluent Monitor: The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where NO_X is monitored to correct the measured emissions rates to 15% O_2. If a CO_2 monitor is installed, the O_2 content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

d. Moisture Correction: If necessary, the permittee shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

e. The permittee shall install, calibrate, maintain, and operate a fuel flow meter (or meters) to continuously measure the heat input to the turbine and duct burner of each unit.
[40 CFR §60.4340(b)(1), §60.4335(b)(2)]

f. Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Each fuel flow meters must meet the applicable requirements, including specifications, initial certification, and quality assurances requirements of 40 CFR Part 75, Appendix D. The fuel flow meters shall be accurate to ±

2.0 percent of the units' maximum flow. Fuel flow meter data shall be automatically recorded with a Data Acquisition and Handling System (DAHS).
[40 CFR §60.4345(c)]

g. The permittee shall install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of each unit in megawatt-hours of each generator; These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see §60.17); and
[40 CFR §60.4340(b)(1), §60.4335(b)(3), §60.5535(d)(1)]

h. Each steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions or the permittee shall Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.
[40 CFR §60.4333(b)(2) and §60.4345(d)]

Performance evaluations and certification tests of the $NO_{x,}$ flow monitors, and wattage meters shall be conducted in accordance with applicability requirements and shall be completed no later than within 180 calendar days after the each of respective unit commences commercial operations and prior to conducting the initial performance tests as noted in Condition 4.3.1. Two copies of the performance evaluations report shall be submitted to the Administrator and Director within 60 days of completion of the evaluation in accordance with Conditions 3.5.3. and 4.5.2.
[40 CFR §75.4(b)(2)]

The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in this condition. For the NO_x CEMS, O_2 and fuel flow meters, the permittee shall implement the QA program and plan described in Section 1 of appendix B to 40 CFR Part 75.
[40 CFR §60.4345(e)]

Monitor(s) that collect data that is used to determine CO_2 emissions shall be maintained in a manner that monitoring availability is at least 95% during the operating hourly in the reporting period as defined in Condition 4.5.3. All other monitors shall be maintained in manner that monitoring availability is at least 75% during the operating hours in the reporting period as defined in Condition 4.5.1.
[40 CFR §60.5540(a)(3)]

4.2.1.2. CEMS Data Requirements for BACT Standards:

The following conditions apply only to the NO_X BACT emissions in Table 4.1.1.a. and mass based limits in Table 4.1.1.b. These requirements cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs. Additional reporting and monitoring may be required by the individual subparts.

a. Data Collection: Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions shall be monitored and recorded during all operation including startup, shutdown, and malfunction.

b. Operating Hours and Operating Days: An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

c. Valid Hour: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

(1) Hours that are not operating hours are not valid hours.

(2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data, and the 1-hour block average is not valid.

d. 3-hour rolling average: For compliance with NOx limits in Table 4.1.1., the hourly NOx CEM data shall be reduced to 3-hour rolling averages. The use of substitution data procedures from 40 CFR Part 75 shall not be utilized.

e. Data Collection: Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, and malfunction.

f. Availability: The semi-annual excess emissions report shall identify monitor availability for each reporting period in which the unit operated.

4.2.1.3. The permittee shall prepare and implement a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR §§75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see 40 CFR §60.5555(c)). Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.5535(a)]

4.2.2. For the purposes of demonstrating compliance with the emission limits of Condition 4.1.3., the permittee shall monitor and record the date, time, and type each startup and shutdown of event for each of the combustion turbine (CT-01 and CT-02) as defined in Condition 4.1.3. and determine the actual emissions of NO_x, CO, VOC, and PM10/PM2.5 Such records shall be maintained in accordance with Condition 3.4.1.

4.2.3. For the purpose of demonstrating compliance for the SO_2 and H_2SO_4 BACT limits in Table 4.1.1.a. of Condition 4.1.1., the permittee shall make demonstration that the fuel (pipeline quality natural gas) combusted in CT-01 and CT-2 contains a sulfur content of no greater that 0.4 grains/100 scf and must either be composed of at least 70 percent methane by volume or have a gross calorific value (GCV) between 950 and 1100 Btu per standard cubic foot using one of the following source information:
[40 CR §60.4360, 60.4365(b), 60.4415(a)(1), 60.4420, 40 CFR §72.2, Section 2.3.1.4.(a) of Appendix D of 40 CFR Part 75]

a. Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the permittee in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in §72.2 of this chapter, except where the results of at least 100 daily (or more frequent) total sulfur samples are provided by the fuel supplier. In that case you may opt to convert these data to monthly averages and then if, for each month, the average total sulfur content is 0.4 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if ≥ 98 percent of the 100 (or more) samples have a total sulfur content of 0.4 grains/100 scf or less and if the GCV or percent methane requirement is also met; or
[40 CFR 60.4415, 4365(b), Section 2.3.1.4.(a)(2) of Appendix D of 40 CFR Part 75]

b. If the requirements of Paragraphs (a) of this condition cannot be met, a fuel may initially qualify as pipeline natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the GCV or percent methane, and the results of the sample analysis show that the fuel meets the definition of pipeline natural gas in 40 CFR §72.2. Use the sampling methods specified in Sections 2.3.3.1.2 and 2.3.4 of Appendix D of 40 CFR 75. The required fuel sample may be obtained and analyzed by the permittee, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of pipeline natural gas in 40 CFR §72.2.
[40 CFR §60.4415, 60.4365(b), Section 2.3.1.4.(a)(3) of Appendix D of 40 CFR Part 75]

i. Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072-06, Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration, ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, or ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, (all incorporated by reference under §75.6 of this part). Alternatively, the gas samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under 40 CFR 60.
[Section 2.3.3.1.2. of Appendix D of 40 CFR Part 75]

ii. Determine the GCV of each gaseous fuel at the frequency specified in this Condition, using one of the following methods: ASTM D1826-94 (Reapproved 1998), ASTM D3588-98, ASTM D4891-89 (Reapproved 2006), GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (all incorporated by reference under §75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2, or 2.3.4.3 of Appendix D of 40 CFR 75, in the calculation of unit hourly heat input rates. Alternatively, the gas samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under 40 CFR 60.
[Section 2.3.4. of Appendix D of 40 CFR Part 75]

c. If the results of the fuel sampling under Paragraph (a) or (b) of this condition show that the fuel does not meet the definition of this condition, but those results are believed to be anomalous, the permittee may document the reasons for believing this in the monitoring plan for the unit and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of in this condition.

[40 CFR §60.4415, 60.4365(b), Section 2.3.1.4.(b) of Appendix D of 40 CFR Part 75]

d. If both combustion turbines are supplied by a common source of gaseous fuel, a single sampling result may be applied to all the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.
[40 CFR §60.4415, 60.4365(b), Section 2.3.1.4.(c) of Appendix D of 40 CFR Part 75]

e. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph (e), sampling "annually" means that at least one sample is taken in each calendar year. If the results of at least 100 daily (or more frequent) total sulfur samples have been provided by the fuel supplier since the last annual assessment of the fuel's sulfur content, the data may be used as follows to satisfy the annual sampling requirement for the current year. If this option is chosen, all of the data provided by the fuel supplier shall be used. First, convert the data to monthly averages. Then, if, for each month, the average total sulfur content is 0.4 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the analysis of the 100 (or more) total sulfur samples since the last annual assessment shows that ≥98 percent of the samples have a total sulfur content of 0.4 grains/100 scf or less and if the GCV or percent methane requirement is also met.
[40 CFR §60.4415, §60.4365(b), Section 2.3.1.4.(e) of Appendix D of 40 CFR Part 75]

f. On-going sampling of the GCV of the pipeline natural gas is required under Paragraph g of this condition.
[40 CFR §60.4415, 60.4365(b), Section 2.3.1.4.(f) of Appendix D of 40 CFR Part 75]

g. Determine the GCV of fuel that is pipeline natural gas, as defined in 40 CFR §72.2 of this chapter, at least once per calendar month. For GCV used in calculations use the specifications in Table D-5 of Appendix D of 40 CFR 75: either the value from the most recent monthly sample, the highest value specified in a contract or tariff sheet, or the highest value from the previous year. The fuel GCV value from the most recent monthly sample shall be used for any month in which that value is higher than a contract limit. If CT-01 and CT-02 combusts pipeline natural gas for less than 48 hours during a calendar month, the sampling and analysis requirement for GCV is waived for that calendar month. The preceding waiver is limited by the condition that at least one analysis for GCV must be performed for each quarter that the unit operates for any amount of time. If multiple GCV samples are taken and analyzed in a particular month, the GCV values from all samples shall be averaged arithmetically to obtain the monthly GCV. Then, apply the monthly average GCV value as described in paragraph c in section 2.3.7 of appendix D of 40 CFR Part 75.
[40 CFR §60.4415, 60.4365(b), Section 2.3.4.1. of Appendix D of 40 CFR Part 75]

Results of such information, analysis to include sampling dates and averages shall be maintained in accordance with Condition 3.4.1.

4.2.4. The permittee shall continuously monitor the temperature of the exhaust from each CT as it enters the oxidation catalyst in at least four equal intervals of each operating hour, these readings shall be used to develop an hourly average temperature for each operation hour and record all instances when the temperature was outside of the acceptable range as stated in Condition 4.1.5.a. and record what mode the turbine was operating in at the time of the instance. Such records shall be maintained in accordance with Condition 3.4.1.

4.2.5. Once per month, the permittee shall record the pressure drop across (at the inlet and outlet) the oxidation catalyst, or any other means the permittee may elect to use to satisfy the catalyst monitoring requirements in Condition 4.1.5.b. for each turbine and determine if the catalyst is operating correctly or if corrective action needs to be taken to restore the catalyst. Such records shall be maintained in accordance with Condition 3.4.1.
[45 CSR §14-7.7]

4.2.6. The permittee shall install, maintained, calibrate, and continuously operate an instrument that measures and records the concentration of ammonia slip from each SCR. Such instrument shall be calibrated at least once per year in accordance with the manufacturer's written procedures.

The permittee shall reduce recorded readings to hourly averages. All valid hourly reading shall be used to develop daily average. Readings that occurred during startup or shutdown mode of the CT shall be consider invalid data and shall not be used in determined the daily average ammonia slip.

Alternative monitoring in lieu of direct measurement of ammonia instrument:

The permittee may install and operate a second NOx CEMS probe located between the duct burners and the SCR, upstream of the stack NOx CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NOx reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Condition 4.1.4.c.; or

The permittee may install and operate a dual stream system of NO_x CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NOx CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NOx CEMS readings (converted and unconverted)

Regardless of which means of monitoring ammonia slip, the permittee shall maintain such system with an instrument availability time (uptime) of no less than 75% of the actual operating hour for the respective CT on a semiannual basis.

Regardless of which mean of monitoring ammonia slip, the permittee shall develop a and implement written plan to certify the monitoring device and or instrument with respect to EPA Conditional Test Method (CTM) 27.

4.2.7. The permittee shall determine record actual heat input of fuel burned by the duct burner of CT-01 and CT-02 on a daily basis and determine the actual capacity factor of each duct burner for each emission unit at the end of each calendar month. Such records shall be maintained in accordance with Condition 3.4.1.

4.2.8. After conducting the initial compliance testing for PM_{10} and $PM_{2.5}$, the permittee shall verify compliance of the visible emissions standard in Condition 4.1.1.b. for each duct burner by conducting Method 22 or Method 9 observations as prescribed in Appendix A of 40 CFR 60 and accordance and with the following timing:

i. Within three months following the calendar year that the respect duct burner has a capacity factor greater than 50%.

ii. During testing as required in Condition 4.3.1. if the duct burner is in operating during such testing.

The permittee shall use either Method 9 or Method 22 for demonstrate or verifying compliance. For using Method 22 in Appendix A of 40 CFR 60 to verify compliance the observation period must be

six minutes with no more than 36 seconds of visible emissions being observation to be a satisfactory observation. Compliance demonstration shall be conduction in accordance with Method 9 from Appendix A of 40 CFR 60 unless the Director approves an alternative method. Record of such observations shall be maintained in accordance with Condition 3.4.1.
[45 CSR 2-8.1.b. and 2-8.3.b.]

4.2.9. For propose of demonstrating the employment of good combustion practices for the CTs w/duct burners as required in Condition 4.1.4.f., the permittee shall continuously monitor the parameter(s) that OEM has determined as indictors that the OEM's proprietary combustion system is working correctly. Records of such monitoring shall be maintained in accordance with Condition 3.4.1.

4.2.10. For the monitoring requirement in Conditions 4.2.2. through 4.2.7., the permittee may use continuous process information system that measures and records the parameters outline in these conditions if the instrument is installed, maintained, and calibrated in accordance with the instrument manufacturer's written instructions and frequency of measurements are no less than prescribe in the condition. If this recorded data is not required or used for demonstrating compliance with NOx, CO, or CO_2 limits or determine excess emissions as required in an emission standard or limit using CEMs data, then such record system not required to be connected to the CEMs data collection system as required in Condition 4.2.1. Should the process information system record more readings than required in these conditions (Conditions 4.2.2. through 4.2.7), then all valid measurements shall be use in an average over the interval as prescribe in the condition. For example, the process information system records the pressure drop across the Oxidation Catalyst once per hour for every operating hour then the system shall determine the monthly average pressure drop by taken the arithmetic average of the 720 valid readings recorded during the respect month.

All records, documentation of maintenance preformed, and system certifications shall be maintained in accordance with Condition 3.4.1.

4.3. Testing Requirements

4.3.1. The initial performance test for CT-01 and CT-02 with the Subpart KKKK standards listed in Table 4.1.1.a. of this permit shall be conducted within 60 days of the unit achieving the maximum production rate at which the affected unit will be operated, but not later than 180 days after initial startup of such emission unit(s) in accordance with the follows requirements.
[40 CFR §60.8(a), §60.4400(b)(5), §60.4405, §60.4415(a)]

Paragraphs a. through d. apply for NO_x Standard and paragraphs e. and i. apply for sulfur content or SO2 standards.

a. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.
[40 CFR §60.4405(a)]

b. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.
[40 CFR §60.4405(b)]

c. Use the test data both to demonstrate compliance with the applicable NO_X emission limit under 40 CFR §60.4320 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR §60.4335.
[40 CFR §60.4405(c)]

d. Compliance with the applicable emission limit in 40 CFR §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of lb/MWh, does not exceed the emission limit.
[40 CFR §60.4405(d)]

e. The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the CT-01 and CT02. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR 75 may be used; or
[40 CFR §60.4415(a)(1)]

f. Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see 40 CFR §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see 40 CFR §60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see 40 CFR §60.17). The fuel analyses of this section may be performed either by the permittee, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17).
[40 CFR §60.4415(a)(1)]

g. If the permittee elects to demonstrate compliance with the SO_2 heat input standard by measuring the SO_2 emissions from the CTs, the permittee shall conduct the testing in accordance with methods and procedures outlined in 40 CFR §§60.4415(a)(3) or (a)(4).
[40 CFR §§60.4415(a)(2) and (a)(2)(i)]

h. Subsequent testing to demonstration compliance with the either sulfur content or SO_2 emissions shall be conducted on an annual basis with no more than 14 calendar months following the previous performance tests.
[40 CFR §60.4415(a)]

i. All emissions testing shall be conducted in accordance with Condition 3.4.1.

4.3.2. For the purposes of demonstrating compliance with the PM, PM_{10}, and $PM_{2.5}$ limits in Condition 4.1.1.a. for each unit (CT-01 & CT-02), the permittee shall conduct an initial performance test within 180 days after initial start-up of the turbine. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method 201 or 201A to be used to measure the "front half" and Method 202 to be used to measure the "back-half" of the particulate matter. During each test, the permittee shall determine the total sulfur in the fuel consumed by the turbine in accordance with Condition 4.2.3. This testing shall consist of three runs of four hours for each run. Records of such testing shall be maintained in accordance with Condition 3.4.1.

Such tests shall be conducted with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output. Should the duct burner be in operation during the test, the permittee shall conduct visible emission observations during each test run using EPA Method 9 to demonstrate compliance with Condition 4.1.1.b.

4.3.3. For the purpose of demonstrating compliance with H_2SO_4 mass rate limit in Condition 4.1.1.a. for each unit (CT-01 & CT-02), the permittee shall conduct an initial performance test within 180 days once the turbine has operated for 300 hours after initial start-up of the turbine. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method CTM-13B or other method approved by the Director. During such testing, the permittee shall continuously measure the inlet temperature of the exhaust entering the SCR. These temperature readings shall be reduced to hourly averages for each test run and included in the test report.

Such tests shall be conduct with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output.

4.3.4. For the purpose of demonstrating compliance with VOC limits in Table 4.1.1.a. and Table 4.1.1.b. for each unit (CT-01 & CT-02), the permittee shall conduct an initial performance test within 180 days once the turbine has operated for 300 hours after initial start-up of the turbine. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method 25A/18.

Such tests shall be conduct with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output. During the three test runs, either the duct burner shall be firing during all periods of the testing or the duct burring not firing.

4.3.5. For the purpose of demonstrating compliance with the formaldehyde limit in Condition 4.1.1.d. for each unit (CT-01 & CT-02), the permittee shall conduct an initial performance test within 180 days once the turbine has operated for 300 hours after initial start-up of the turbine. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method 320 of Appendix A of 40 CFR Part 63, or ASTM D6348-12e1 provided that the test plan preparation and implementation provisions of Annexes A1 through A8 are followed and the %R as determined in Annex A5 is equal or greater than 70% and less than or equal to 130%. The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound using the following equation:

Reported Results = ((Measured Concentration in Stack)/(%R)) × 100

Such tests shall be conduct with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output. During the three test runs, the duct burner shall be firing during all periods of the testing.

During such testing, the permittee will either verify or re-establish operating parameters for the oxidation catalysis.

4.3.6. During each test run conducted as required in Section 4.3., the permittee shall measure the amount of fuel consumed; gross power output; steam output of the HRSG; gross power output of the steam turbine if applicable; ammonia slip; temperature at the inlet of the SCR and oxidation catalyst. The measured values from each test run shall be included with the test report as required in Condition 3.3.1.

4.3.7. The permittee shall conduct subsequent testing as outline in the respective condition is required when the either indicator is meet in accordance with the timing as outlined in the following schedule:

Table 4.3.7. Subsequent Testing Schedule

Condition No.	Indicator 1	Indicator 2	Timing
4.3.2.	Annual fuel gas Sulfur Content is greater than 0.3 gr/100 scf	Annual average ammonia slip is greater than 5 ppm	Within 120 days after the end of the year

4.3.3.	Annual fuel gas Sulfur Content is greater than 0.4 gr/100 scf	Annual average inlet temperature to the SCR is less than 600 F excluding temperatures recorded during startup and shutdown events.	Within 120 days after the end of the year
4.3.4.	Monthly average CO Concentration is above 2 ppm @15% O_2	Replacement of the Oxidation Catalyst	Within 90 days of triggering the indictor

Annual sulfur content and ammonia slip shall be on a calendar year basis.

4.3.8. Once the duct burner (DB) for the respective combustion turbine (CT) has reached an annual capacity factor of greater than 50%, the permittee shall conduct a performance test to demonstration initial compliance with the PM limit in Table 4.1.1.a. (See Condition 4.1.1.a.) within 120 days following the end of the calendar year that DB had an annual capacity factor greater than 50%. The permittee shall conduct this demonstration in accordance with applicable method(s) prescribed in 45 CSR 2-8.1.b., 45 CSR 2 – Appendix, and Condition 3.3.1. During the performance test, the DB shall be either operating a firing rate of 90% or greater of the permitted heat input or operating at 90% or greater of the highest heat input during the previous calendar year. The highest heat input shall be the highest of the daily average of the hourly heat input for the operating day excluding hours of no DB firing. Results of this demonstration shall be reported in accordance with Conditions 3.3.1. and 3.5.3. Records of this demonstration shall be maintained in accordance with Condition 3.4.1.

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. The following is requirements shall be used in determining compliance with the Subpart KKKK NOx limits and identifying excess emissions from CEMs data:

All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).
[40 CFR 60.4350(a)]

For each unit operating hour in which a valid hourly average, as described in 40 CFR§60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm and lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.
[40 CFR 60.4350(b)]

Correction of measured NO_X concentrations to 15 percent O_2 is not allowed for the NOx NSPS Subpart KKKK limit listed in Table 4.1.1.a.
[40 CFR 60.4350(c)]

Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in Subpart D of 40 CFR Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c) and in Condition 4.5.1.
[40 CFR 60.4350(d)]

All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
[40 CFR 60.4350(e)]

Calculate the hourly average NO_X emission rates, in units of the emission standards under 40 CFR §60.4320, using the following equation for units complying with the output based standard:

a. For complying with the NO_x output-based standard, the permittee shall use the following equation (Equation 1 of 40 CFR 60, Subpart KKKK), except that the gross energy output (P) is calculated as the sum of the total electrical and thermal energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$E = \frac{(NO_X)_h \times (HI)_h}{P}$$ Equation 1 of 40 CFR 60, Subpart KKKK

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

$$P = (P_e)_t + (P_e)_c + P_s + P_o$$ Equation 2 of 40 CFR 60 Subpart KKKK

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_s = \frac{Q \times H}{3.413 \times 10^6\ Btu/MWh}$$ Equation 3 of 40 CFR 60 Subpart KKKK

Where:

P_s = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413×10^6 = conversion from Btu/h to MW.

P_o = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

"30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine-unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30-unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours. The permittee shall determine excess emissions for each 30-day rolling average NO_X emission rate is greater than the Subpart KKKK Standard in Table 4.1.1.a. of this permit.
[40 CFR §60.4380(b)(1)]

A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, diluent gas (CO_2 or O_2) concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee will use this information for compliance purposes.
[40 CFR 60.4380(b)(2)]

A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.
[40 CFR 60.4380(c)(2)]

4.4.5. For the purpose determine compliance with the SUSD mass limits in Condition 4.1.3.e., the permittee shall determine for each operating day the total mass rate for each pollutant listed in Condition 4.1.3.e. that was emitted by the emission unit during SUSD periods and sum this total with the previous 29 operate day totals. The permittee shall determine if Excessive SUSD has occurred by determining if the mass total of the 30-day rolling total by pollutant is greater than the limit in Condition 4.1.3.e. for each pollutant. NO_x and CO mass emissions from SUSD shall be based on CEM and operating data. VOCs and $PM_{10}/PM_{2.5}$ shall be on actual operating data and best available information/data. Records of each of the 30-day mass rate and if excessive emissions were determined shall be maintained in accordance with Condition 3.4.1.

4.4.6. The following is requirements shall be used in determining compliance with the Subpart TTTT GHG (CO_2) limits in Table 4.1.1.a. for CT-01 and CT-02 and identifying excess emissions:

The permittee shall demonstrate compliance with the output based standard unless the permittee can demonstrate that the unit is a no longer a base loaded unit as defined in Subpart TTTT.

The permittee shall determine the hourly CO_2 mass emissions according to following paragraphs of this condition.
[40 CFR §60.5535(c)]

At times when the output-based standard is applicable, the permittee must implement the applicable procedures in appendix D to 40 CFR 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.
[40 CFR §60.5535(c)(1)]

For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR 75 to calculate the hourly CO_2 mass emission rate (tons/h). The permittee may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR 75 , and the permittee may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature.
[40 CFR §60.5535(c)(2)]

For each “valid operating hour” (as defined in 40 CFR §60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR §72.2 of this chapter), to convert it to tons of CO2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.
[40 CFR §60.5535(c)(3)]

The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR §75.57(e) of this chapter and must be reported

electronically under 40 CFR §75.64(a)(6) of this chapter. The permittee must use these data to calculate the hourly CO_2 mass emissions.
[40 CFR §60.5535(c)(4)]

For each valid operating hour of the compliance period that was used in 40 CFR §60.5540(a)(4) of this section to calculate the total CO2 mass emissions, the permittee must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in 40 CFR §60.5540(a)(3)(i) and (a)(3)(ii), as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to 40 CFR §60.5540(a)(1)(i), if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to 40 CFR §60.5540(a)(1)(i) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

The permittee shall calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU (CT-01 or CT-02) that determined using the following for all the valid operating hours in the applicable compliance period. Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly gross or net energy output (consistent with §60.5520) value reported under 40 CFR 75 to MWh, multiply by the corresponding EGU or stack operating time.
[40 CFR 60.5540(a)(5), (a)(6)]

$$P_{gross/net} = \frac{(P_e)_{ST} + (P_e)_{CT} - (P_e)_{IE} - (P_e)_A}{TDF} + [(P_t)_{PS} + (P_t)_{HR} + (P_t)_{IE}] \quad \text{Eq. 2 of Subpart TTTT}$$

Where:

Pgross/net = In accordance with 40 CFR §60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in 40 CFR §60.5540(a)(1)) in MWh.

(P_e)ST = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

(P_e)CT = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

(P_e)IE = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

(P_e)FW = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

(P_e)A = Electric energy used for any auxiliary loads in MWh. Not applicable for determining Pgross.

(P_t)PS = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(P_t)HR$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(P_t)IE$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

Calculation of annual basis for standard. Sources complying with energy output-based standards must calculate the basis (i.e., denominator) of their actual annual emission rate in accordance with 40 CFR §60.5540(a)(6)(i). Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph 40 CFR§ 60.5540(a)(6)(ii) of this section.

In accordance with output-based standard (40 CFR §60.5520), the permittee shall calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under 40 CFR §60.5540(a)(5) of this section for all the valid operating hours in the applicable compliance period.

4.4.7. The permittee shall determine the NO_x and CO concertation for each operation hour that the CT-01 and CT-02 corrected to 15% oxygen content for operating hour that the unit was not experiencing a SUSD as defined in Condition 4.1.3. and determine the 3-hour rolling average. Each hourly determination shall be based on all valid data using Method 19. A new 3-hour rolling average for NO_x and CO shall be determined for each operating hour. Records of each of these hourly rolling average concentration determinations shall be maintained in accordance with Condition 3.4.1.

Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 15 percent oxygen (dry basis). At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2). Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

4.4.8. For the purpose of determining compliance with the NO_x and CO hourly mass rate limits in Table 4.1.1.b., the permittee shall determine the hourly NOx and CO emission rate for CT-01 and CT-02 for each operating hourly and the 3-hour rolling average. Only valid CEM or operating shall be used for such a determination and shall not include data while the emission unit was not experiencing a SUSD event as defined in Condition 4.1.3. Each hourly determination shall be performed in accordance the applicable methods in Method 19 and corrected to zero oxygen content. At the end of each month, the permittee shall determine if any excess emission occurred, which means any three-hour rolling average is greater than the applicable limit in Table 4.1.1.b. Records of each of these hourly rolling average concentration determinations shall be maintained in accordance with Condition 3.4.1.

4.5. Notification Requirements

4.5.1. The permittee shall prepare and submit an excess emission report on a semi-annual basis to the Director and Administrator for NOx emissions from CT-01 and CT-02 as required by Subpart

KKKK of 40 CFR 60. The initial compliance period that be from initial startup up of the unit to either December 31 or June 30 which ever date comes first. Subsequent reporting periods shall be every six months thereafter (e.g., January 1 to June 30, July 1 to December 31). Reports must be submitted by no later than 30th day following the end of the reporting period. Each report must contain or
[40 CFR §60.7(c), §60.4395, §60.4380]

Excess Emissions of sulfur dioxide emissions shall mean the total sulfur content of the fuel being combusted in the either CT-01 or CT-02 exceeds the limit specified in 40 CFR §60.4330 (See Table 4.1.1.a of Condition 4.1.1.a. SO_2 limit for Subpart KKKK);
[40 CFR §60.4420]

Excess Emissions of NO_x emissions means a specified averaging period over which the NOx emissions are higher that the applicable emission limit in 40 CFR 60.4320 (See Table 4.1.1.a. of Condition 4.1.1.a. NOx limit for Subpart KKKK).
[40 CFR §60.4420]

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.
[40 CFR §60.7(c), §60.4375(a), §60.4380]

The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each period of excess emissions. The process operating time during the reporting period.
[40 CFR §60.7(c)(1)]

Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted.
[40 CFR §60.7(c)(2)]

The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
[40 CFR §60.7(c)(3)]

When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
[40 CFR §60.7(c)(4)]

The summary report form shall contain the information and be in the format shown in Attachment A unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
[40 CFR §60.7(d)]

If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted, and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Administrator.
[40 CFR §60.7(d)(1)]

If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5

percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.
[40 CFR §60.7(d)(2)

4.5.2. The permittee shall submit to the Director within 60 days of completion of CEMS performance evaluation for CT-01 and CT-02 two copies of the performance evaluation report for each unit to satisfy Part 60 notification requirements for certifying the CEMS.
[40 CFR §§60.13(c), (c)(2)]

4.5.3. Within 30 days after the end of the initial compliance period (i.e., no more than 30 days after the first 12-operating-month compliance period), the permittee must make an initial compliance determination for CT-01 and CT-02 with respect to the applicable emissions standard in Table 2 of Subpart TTTT, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined item l. of this condition. Subsequent report shall be submitted quarterly.
[40 CFR §60.5525(c)]

a. The first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under 40 CFR 63.5555(c)(3)(i), for units subject to the Acid Rain Program;
[40 CFR §60.5525(c)(1) and (c)(1)(i)]

b. Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. The permittee must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in 40 CFR §60.5540. The permittee must report the dates (month and year) of the first and twelfth operating months in each compliance period for which the permittee performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, the permittee must include a statement to that effect;

c. If one or more compliance periods end in the quarter, the permittee must identify each operating month in the calendar quarter where the unit violate the applicable CO_2 emission standard;

d. If one or more compliance periods end in the quarter and there are no violations for the affected EGU, the permittee must include a statement indicating this in the report;

e. The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (i.e., the total number of valid operating hours (as defined in 40 CFR §60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

f. Consistent with 40 CFR §60.5520, the CO_2 emissions standard (as identified in table 2 of Subpart TTTT) with which your affected EGU must comply; and

g. Consistent with 40 CFR §60.5520, an indication whether the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

h. In the final quarterly report of each calendar year, the permittee must include the following:

i. Consistent with 40 CFR §60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

ii. The potential electric output of the EGU.

i. The permittee must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.
[40 CFR 60.5555(b)]

j. For affected EGUs under this subpart that are also subject to the Acid Rain Program, the permittee must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.
[40 CFR 60.5555(c)(1)]

k. For affected EGUs under this subpart that are not in the Acid Rain Program, the permittee must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.
[40 CFR 60.5555(c)(2)]

l. For all newly constructed affected EGUs under Subpart TTTT that are also subject to the Acid Rain Program, the permittee must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a) of this chapter, i.e., beginning with data recorded on and after the earlier of:
[40 CFR 60.5555(c)(3)(i)]

i. The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or
[40 CFR 60.5555(c)(3)(i)(A)]

ii. 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).
[40 CFR 60.5555(c)(3)(i)(B)]

5.0. Specific Requirements for the RICE for the Emergency Generator and Fire Water Pump (EG-1 & FWP-1)

5.1. Limitations and Standards

5.1.1. The following conditions and requirements are specific to the internal combustion engine for the Emergency Generator #1 (ID EG-01):

a. Emissions shall not exceed the following:

i. NO_x + Non-Methane Hydrocarbons (NMHC) emissions from the engine shall not exceed 6.4 grams of NO_x per kilowatt-hour (g/kW-hr).
[40 CFR §60.4205(b) and §60.4202(b)(2); 40 CFR 1039, Appendix I, Table 2 – Tier 2 Emission Standards; and 45 CSR §14-8.3]

ii. CO emissions from the engine shall not exceed 0.41 g/kW-hr.
[40 CFR §60.4205(b) and §60.4202(b)(2); 40 CFR 1039, Appendix I, Table 2 – Tier 2 Emission Standards; and 45 CSR §14-8.3]

iii. PM/PM10 emissions from the engine shall not exceed 0.20 g/kW-hr.
[40 CFR §60.4205(b) and §60.4202(b)(2); 40 CFR 1039, Appendix I, Table 2 – Tier 2 Emission Standards; and 45 CSR §14-8.3]

iv. Sulfur dioxide emissions from the engine shall not exceed 0.06 pounds per hour. Compliance with this limit is satisfied through compliance with Condition 5.1.3. of this permit.
[40 CFR §60.4207(d) and 45 CSR §14-8.3]

b. The permittee shall satisfy compliance with the emission standards in item a of this condition, expect for the sulfur dioxide limit in item a. subitem iv., by purchasing an engine certified to 40 CFR part 89 or 40 CFR 94, as application for the same model year and maximum engine power. The model year of the engine shall be 2021 or later. The mass rate of the certified emissions from manufacturer of the purchased engine shall not exceed the rates listed in Table 5.1.1.c. The engine must be installed and configured according to the manufacturer's specifications.
[40 CFR 60.4211(b)(1)]

c. Mass Hourly emissions from the engine shall not exceed the following rates on a 3-hour average basis.

Table 5.1.1.c. Mass Emissions Limits for EG-01	
Pollutant	**Hourly Rate (lb/hr)**
Oxides of Nitrogen (NO_x)	24.6
Carbon Monoxide (CO)	1.94
Volatile Organic Compounds (VOCs)	0.46
$PM/PM_{10}/PM_{2.5}$	0.23
Carbon Dioxide Equivalence (CO_2e)	1,961
Total Hazardous Air Pollutants (HAPs)	0.03
Formaldehyde	0.001

d. The stack for emission point EG-1 shall have a diameter no greater than 0.203 meters and height above ground elevation of no less than 22.86 meters.

e. The engine for EG-01 shall not have a nameplate power greater than the design capacity listed in Table 1.0 for EG-01.

f. The engine for EG-01 shall not have a displacement greater than 10 liters per cylinder.

g. When in operation other than startup or shutdown periods, the engine for EG-01 shall be a constant-speed engine.

5.1.2. The following conditions and requirements are specific to the internal combustion engine for the Fire Water Pump #1 (ID FWP-1):

a. Emissions shall not exceed the following:

i. NO_x + Non-Methane Hydrocarbons (NMHC) emissions from the engine shall not exceed 4.0 grams of NO_x per kilowatt-hour (g/kW-hr).
[40 CFR §60.4205(c) and §60.4202(d); Table 4 to Subpart IIII of Part 60 - Emission Standards for Stationary Fire Pump Engines, and 45 CSR §14-8.3]

ii. CO emissions from the engine shall not exceed 0.6 g/kW-hr.
[40 CFR §60.4205(c) and §60.4202(d); Table 4 to Subpart IIII of Part 60 - Emission Standards for Stationary Fire Pump Engines, and 45 CSR §14-8.3]

iii. PM/PM10 emissions from the engine shall not exceed 0.20 g/kW-hr.
[40 CFR §60.4205(c) and §60.4202(d); Table 4 to Subpart IIII of Part 60 - Emission Standards for Stationary Fire Pump Engines, and 45 CSR §14-8.3]

iv. Sulfur dioxide emissions from the engine shall not exceed 0.001 pounds per hour. Compliance with this limit is satisfied through compliance with Condition 5.1.3. of this permit.
[40 CFR §60.4207(d) and 45 CSR §14-8.3]

b. The permittee shall satisfy compliance with the emission standards in item a, expect for sulfur dioxide limit in item a. subitem iv., of this condition by purchasing an engine certified to 40 CFR part 89 or 40 CFR 94, as application for the same model year and maximum engine power. The model year of the engine shall be 2021 or later. The mass rate of the certified emissions from manufacturer of the purchased engine shall not exceed the rates listed in Table 5.1.2.c. The engine must be installed and configured according to the manufacturer's specifications.
[40 CFR 60.4211(b)(1)]

c. Mass Hourly emissions from the engine shall not exceed the following rates on a 3-hour average basis.

Table 5.1.1.c. Mass Emissions Limits for FWP-1	
Pollutant	**Hourly Rate (lb/hr)**
Oxides of Nitrogen (NO_x)	1.59
Carbon Monoxide (CO)	1.38
Volatile Organic Compounds (VOCs)	1.59
$PM/PM_{10}/PM_{2.5}$	0.08
Carbon Dioxide Equivalence (CO_2e)	417.8

Total Hazardous Air Pollutants (HAPs)	0.01
Formaldehyde (HAP)	0.003

d. The engine for FWP-1 shall not have a nameplate power greater than the design capacity listed in Table 1.0 for FWP-1.

5.1.3. The permittee shall operate the engine for the emergency generator (ID. EG-1) and firewater pump (FWP-1) in accordance with the following the requirements.

a. There is no time limit on the use of each engine in emergency situations. Each engine can operate for combined non-emergency purposes, which include maintenance and testing, and other non-emergency use for a maximum of 100 hours per year on a calendar year basis. For the non-emergency situations, each engine cannot be operated for peak shaving or non-emergency demand response, or to generate income for the facility to an electric gird or otherwise provide power as part of a financial arrangement with another entity.
[40 CFR §§60.4211(f), (f)(1), & (f)(2)(i)]

b. Each engine shall be equipped with a non-resettable hour-meter prior to start-up.
[40 CFR §60.4237(a)]

c. The permittee shall keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate each engine and associated control device (if equipped) in a manner consistent with good air pollution control practice for minimizing emissions.
[40 CFR §60.4243(b)(2)(ii)]

d. In accordance with 45 CSR §14-8.3., the permittee shall implement and maintain the following measures in applying the Best Available Control Technology for PM, PM10, PM2.5 and Greenhouse Gas emissions to the engine by:

i. Limiting the fuel for each engine to only diesel fuel that meeting the following standards.

1. Sulfur standard. Maximum sulfur content of 15 ppm.
[40 CFR 60.4207(b), 40 CFR 1090.305(b), 40 CFR 14-8.3]

2. Cetane index or aromatic content. Diesel fuel must meet one of the following standards:
[40 CFR 60.4207(b), 40 CFR 1090.305(c), 40 CFR 14-8.3]

a. Minimum cetane index of 40; or
[40 CFR §60.4207(b), 40 CFR §1090.305(c)(1), 40 CFR §14-8.3]

b. Maximum aromatic content of 35 volume percent.
[40 CFR §60.4207(b), 40 CFR §1090.305(c)(2), 40 CFR §14-8.3]

ii. Tune-up of each engine once every five years in accordance with the manufacturer's specifications.
[45 CSR §14-8.3]

5.2. Monitoring Requirements

5.2.1. The permittee shall keep records of the hours of operation for each engine (EG-01 & FWP-1). The records must document how many hours are spent for emergency operation, including what classified the operation as an emergency, and how many hours spent for non-emergency operation with corresponding reason for the non-operation. At the end of each calendar year, the permittee totals the hours operation for emergency and non-emergency operations of each engine. Such

records shall be maintained in accordance with Condition 3.4.1. and must be in a manner to demonstrate compliance with the operating limits of Condition 5.1.3.a.
[40 CFR §60.4214(b)]

5.3. Recordkeeping Requirements

5.3.1. The permittee shall maintain records of maintenance preformed on engines for EG-01 and FWP-01, which shall include tune-up performed as required in Condition 5.1.3.d.ii. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.4 (a)(2)]

5.4. Reporting Requirements

5.4.1. The permittee shall submit an initial notification to the Director of the engine for the emergency generator (EG-01) to satisfy initial notification requirements of Subpart ZZZZ of 40 CFR 63 within 15 calendar days after initial startup date of the emergency generator (EG-01). Such notification shall include the following information and a statement that engine for the emergency generator has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions) and in accordance with Condition 3.4.1.
[40 CFR §§63.9, §63.6590(b) and §63.6645(f)]

a. The name and address of permittee;
[40 CFR §63.9(2)(i)]

b. The address (i.e., physical location) of the affected source (emergency generator);
[40 CFR 63.9(2)(ii)]

c. An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;
[40 CFR §63.9(2)(iii)]

d. A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted; and
[40 CFR §63.9(2)(iv)]

e. A statement of whether the affected source is a major source or an area source.
[40 CFR §63.9(2)(v)]

6.0 Specific Requirements for Fuel Gas Heaters FGH-1 and FGH-2

6.1. Limitations and Standards

6.1.1. The following conditions and requirements are specific to the fuel gas heater (FGH-1 and FGH-2):

a. NO_x emissions emitted to the atmosphere from each heater shall not exceed 1.10 tons per year on a rolling 12-month basis.

b. CO emissions emitted to the atmosphere from each heater shall not exceed 1.19 tons per year on a rolling 12-month basis.

c. PM, PM_{10}, and $PM_{2.5}$ emissions to the atmosphere from each heater shall not exceed 0.24 tons per year on a rolling yearly total basis, which includes filterable and condensable forms of particulate matter.

d. Visible emissions from the corresponding emission point associated for each heater shall not be greater than ten (10) percent opacity based on a six-minute average.
[45 CSR §2-3.1.]

e. Emissions of CO_2e from the heaters shall not exceed 4,029 tons per year on a rolling 12-month basis.

f. Each heater shall not be designed or constructed with a maximum design heat input in excess of 7.0 MMBtu/hr. This condition satisfies compliance with the limitation of 45 CSR §2-3.1.
[45 CSR 2A-3.1.a.]

g. In accordance with 45 CSR §14-8.3., the permittee shall implement and maintain the following measures in applying the Best Available Control Technology for NOx, CO, PM, PM_{10}, $PM_{2.5,}$ VOCs and Greenhouse Gases emissions generated from each heater by:

i. Limiting the fuel to each heater to only pipeline quality natural gas with a sulfur content of 0.4 grains of total sulfur per 100 scf.
[45 CSR §10-3.3.f.]

ii. The permittee shall conduct tune-ups of each heater in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. The initial tune up for each heater shall be conducted no later than 25 months after initial startup of the heater. Subsequent biennial tune ups shall be conducted no later than 25 months after the previous tune up. If the unit is not operating on the required date for a tune-up, then the tune-up must be conducted within 30 calendar days of re-starting of the unit. These tune-ups shall consist of the following:
[40 CFR §63.7515(d), §63.7540(a)(11)]

1. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (The permittee may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection).
[40 CFR 7540(a)(10)(i)]

2. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
[40 CFR 7540(a)(10)(ii)]

3. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection

until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection);
[40 CFR 7540(a)(10)(iii)]

4. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject; and
[40 CFR 7540(a)(10)(iv)]

5. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.
[40 CFR 7540(a)(10)(v)]

[45 CSR 14-8.3, 40 CFR §63.7500), and Table 3 to Subpart DDDDD of Part 63—Work Practice Standards]

6.2. Recordkeeping Requirements

6.2.1. The permittee shall record the actual amount of fuel consumed or actual operating hours for each heater (FGH-1 & FGH-2) for each calendar month and determine actual emissions emitted during the corresponding month. Using the previous 12-months of actual emissions, the permittee shall demonstrate compliance with the annual limits of items a through d of Condition 6.1.1. Such records shall be maintained in accordance with Condition 3.4.1.

6.2.2. The permittee shall keep the following records in accordance with 40 CFR §63.7540(a)(10)(vi) as required to be conducted in Condition 6.1.1.f.ii. for each heater:
[40 CFR 63.7540(a)(10)(vi)]

a. The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler using a portable combustion analyzer
[40 CFR §63.7540(a)(10)(vi)(A)]

b. A description of any corrective actions taken as a part of the tune-up; and
[40 CFR §63.7540(a)(10)(vi)(B)]

c. The type and amount of fuel used over the 12 months prior to the tune-up of the unit, but only if the unit was physically and legally capable of using more than one type of fuel during that period.
[40 CFR §63.7540(a)(10)(vi)(C)]

These records shall be maintained in accordance with Condition 3.4.1.

6.3. Reporting Requirements

6.3.1. The permittee shall submit a "Notification of Compliance Status" for heaters identified as FGH-01 and FGH-02 to the Director before the close of business on the sixtieth (60^{th}) day after completion of the initial compliance demonstration as required in Condition 6.1.7.f.ii. Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the information specified in 40 CFR §§63.7545(e)(1), and (8), which includes a statement the initial tune-up for each heater was completed.
[40CFR§63.7545(e)]

4.5.3. The permittee shall submit "Biennial Compliance Reports" for FGH-01 and FGH-02 electronically using CEDRI that is accessed through the EPA's Center Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form for this report is not available in CEDRI at the time the report is due, the permittee shall submit the report to the Administrator and Director using the addresses listed in Condition 3.5.3. The first biennial (every two years) compliance report shall be submitted no later than two years after the initial start-up of the unit and the first date ending on January 31. Subsequent reports shall be submitted once every two years afterwards. Such reports shall contain the information specified in 40 CFR §§63.7550(c)(1) which are:

a. Permittee and facility name, and address;

b. Process unit information, emission limitations, and operating limitations;

c. Date of report and beginning and ending dates of the reporting period;

d. Include the date of the most recent tune-up for each boiler; and

e. Include the date of the most recent burner inspection if it was not done on a five-year frequency and was delayed until the next scheduled or unscheduled unit shutdown.

The permittee shall maintain records of such reports in accordance with Condition 3.4.1.
[40CFR §§63.7550(b), (b)(1), (c)(1), & (c)(5)(i) though (iv) and (xiv), and (h)(3)]

7.0. Specific Requirements for Collection of Fugitive Emissions Facility-Wide

7.1. Limitations and Standards

7.1.1 The permittee must reduce fugitive greenhouse gas emissions from the permitted facility by complying with the following requirements.

a. The permittee shall develop and implement a monitoring plan in accordance with Condition 7.1.2.

b. Subsequent monitoring surveys shall be conducted at least annually and at least 30 days prior to any major planned maintenance outage. Major planned maintenance outage shall mean any planned outage that is schedule for more than 14 days.

c. The fugitive emission components at the facility shall include all above grade components or equipment that associated the natural gas fuel supply piping that is connected to all the natural gas combustion sources cover under this permit.

d. Fugitive emissions are defined as: any visible emission from a fugitive emission component observed using optical gas imaging equipment or an instrument reading of 500 ppm or greater using Method 21.

The permittee shall repair all detected fugitive emissions in accordance with the following:

i. Within 30 calendar days after detection; or

ii. If the repair or replacement is technically infeasible, would require a vent blowdown, a facility shutdown, or is unsafe to repair during operation of the unit, then the repair or replacement must be completed during the next scheduled facility shutdown, after a planned vent blowdown, or within 2 years, whichever is earlier.

e. Once the repair or replacement is completed, the identified component shall be resurveyed as soon as practicable, but no later than 30 days after being repaired or 30 days after restarting the unit if a unit or station was shut down during while make the repairs, to ensure that there are no fugitive emissions.

f. For repairs completed after the monitoring survey, the permittee may resurvey the repaired component using either U.S. EPA Method 21, Alternative Screening Procedure of Method 21, or optical gas imaging.

g. When using Method 21 to resurvey a repair, the fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above the background or when no soap bubbles are observed when the Alternative Screening Procedure is used. The procedures outlined in 40 CFR 60.5397a(c)(8)(ii) must be followed when using Method 21. Use of the Alternative Screening Procedure must be conducted in accordance with the following:

i. Components that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Components that have these conditions present cannot be surveyed using the Alternative Screening Procedure.

ii. Spray a soap solution over all potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, Method 21 instructions shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

h. When using optical gas imaging to resurvey a repair, the fugitive emissions component is repaired when the optical gas imaging equipment show no indication of visible emissions. The procedure outlined in Condition 7.1.2.f. must be followed.

i. For the all the sulfur hexafluoride (SF_6) circuit breakers at the facility, the permittee shall install and maintain the sealed enclosed-pressure circuit breakers equipped with low-pressure alarms and a low-pressure lockout where the alarms are triggered when 10% (by weight) of the sulfur hexafluoride (SF_6) (by weight) has escaped. When the alarms are triggered, the permittee shall take immediate corrective action and fix the circuit breaker units to a like new state to prevent the emission of sulfur hexafluoride (SF_6) to the maximum extent practicable. Records of all maintenance activities of the circuit breaker and alarm system shall be maintained in accordance with Condition 3.4.1.
[45 CSR §14-8.3]

7.1.2. The permittee shall develop a plan to monitor all fugitive emission components at the permitted facility. At a minimum, this fugitive emissions monitoring plan must include the elements specified in the following, at a minimum:

a. Technique for determining fugitive emissions (i.e., Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

b. Manufacturer and model number of fugitive emissions detection equipment to be used.

c. Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. The permittee's repair schedule must meet the requirements of Condition 7.1.1.f.

d. Procedures and timeframes for verifying fugitive emission component repairs.

e. Records that will be kept and the length of time records will be kept.

7.1.3. If the permittee elects to use optical gas imaging techniques to conduct monitoring surveys, the plan must also include the following elements:

a. Initial verification that the optical gas imaging equipment used in the survey meets the following:

i. The optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

ii. The optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of less than 60 grams per hour from a quarter inch diameter orifice.

b. Procedures to perform a daily verification check of the equipment.

c. Procedure for determining the operator's maximum viewing distance from the components and how the operator will ensure that this distance is maintained.

d. Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

e. Procedures for conducting surveys, shall including the following:

i. How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

ii. How the operator will deal with adverse monitoring conditions, such as wind.

iii. How the operator will deal with interferences (e.g., steam).

f. Training and experience needed prior to performing surveys.

g. Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

7.1.4. If the permittee elects to use Method 21 technique to conduct monitoring surveys, the plan must also include the following elements:

a. Verification that the monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using an FID-based instrument. If the permittee wishes to use an analyzer other than an FID-based instrument, the permittee must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using an FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to the permittee's compound of interest).

b. Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

7.1.5. The monitoring plan must include the following elements at the permitted facility:

a. Sitemap.

b. A defined observation path that ensures that all fugitive emissions components are within sight of the path. The path must include distinguishable marking that indicates or identifies where the observation is being taken with relationship to specific collection of fugitive components. The observation path must account for interferences.

c. If the permittee is using Method 21, the plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive emissions components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).

7.1.6. Each monitoring survey shall observe each fugitive emission component, as defined in 40 CFR 60.5430a, for fugitive emissions.

7.1.7. The permittee may elect to switch between monitoring techniques in the monitoring plan. If such an election occurs, the permittee must update the monitoring plan as required in Condition 7.1.2. for the site and notify the Director in accordance with Condition 3.5.3. within 15 days prior to the next monitoring survey as required in Condition 7.1.1.c.

7.2 Recordkeeping Requirements

7.2.1. The permittee shall maintain records of each monitoring survey as required in Condition 7.1.1. Such records shall contain the following information:

a. Date of the survey.

b. Beginning and end time of the survey.

c. Name of operator(s) performing survey. The permittee must note the training and experience of the operator.

d. Monitoring instrument used.

e. When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used to conduct the monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at the station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

f. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

g. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

h. Documentation of each fugitive emission, including the information specified as follows:

i. Location.

ii. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

iii. Number and type of components for which fugitive emissions were detected.

iv. Number and type of fugitive emissions components that were not repaired as required in Condition 7.1.2.f.

v. A digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in . The digital photograph or video must clearly identify the location of the component that must be repaired.

vi. Repair methods applied in each attempt to repair the fugitive emissions components.

vii. Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

viii. The date of successful repair of the fugitive emissions component.

ix. Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

Such records shall be maintained in accordance with Condition 3.4.1. Any records submitted as required in Condition 7.3.1. in an electronic format shall be maintained in the electric format as submitted.

7.3. Reporting Requirements

7.3.1. The permittee shall submit to the Director a report of each annual survey. Records of submittal shall be maintained in accordance with Condition 3.4.1. At minimum, these reports shall contain the following information:

a. Date of each monitoring survey.

b. Beginning and end time of each survey.

c. Name of operator(s) performing survey. If the survey is performed by optical gas imaging, the permittee must note the training and experience of the operator.

d. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

e. Monitoring instrument used.

f. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

g. Number and type of components for which fugitive emissions were detected.

h. Number and type of fugitive emissions components that were not repaired as required in Condition 7.1.1.f.

i. The date of successful repair of the fugitive emissions component.

j. Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

k. Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

8.0. Specific Requirements for the Mechanical Draft Cooling Tower (WCT-1)

8.1. Limitations and Standards

8.1.1 The conditions and requirements in the following subdivisions are specific to the mechanical draft cooling tower (ID #ST-1):

a. Emissions of PM, PM-10, and $PM_{2.5}$ shall be controlled with a 0.0005% drift eliminator or an equivalent control technology.

i. PM and PM_{10} emissions emitted to the atmosphere from the Cooling Tower (EP #WCT-1) shall not exceed 2.16 lb/hr and 9.47 TPY.

ii. $PM_{2.5}$ emissions emitted to the atmosphere from the Cooling Tower (EP #WCT-1) shall not exceed 1.08 lb/hr and 4.73 TPY.

8.2. Monitoring Requirements

8.2.1. For the purpose of determining compliance with this emission limit in Condition 8.1.1., the permittee shall monitor cooling water flow rate on a continuous and either the concentration of total dissolved solids contained in the circulating water of the cooling tower or specific conductivity on a daily basis. If the permittee uses a correlation curve or ratio between total dissolve solids concentration and specific conductivity, the Director or his/her representative may request the permittee to verify the correlation at any reasonable time with just cause. The permittee shall determine the PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling towers using a method that accuracy predicts these specific pollutants from mechanical draft cooling towers. Such determination shall be conduct on a monthly basis. Records of such monitoring and determinations shall be maintained in accordance with Condition 3.4.1. of this permit.

8.3. Testing Requirements

8.3.1. The permittee shall perform an initial drift test within 180 days after startup on the cooling towers. Such testing shall be conducted in accordance with Condition 3.3.1. of this permit. Records of such testing shall be maintained in accordance with Condition 3.4.1 of this permit.

Appendix A – Summary Report - Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO2/NOX/TRS/H2S/CO/Opacity)

Reporting period dates: From ____________________ to ____________________

Company:

Emission Limitation
Address:

Monitor Manufacturer and Model No.
Date of Latest CMS Certification or Audit
Process Unit(s) Description:
Total source operating time in reporting period[1]

Emission data summary[1]		CMS performance summary[1]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	%[2]	3. [Total CMS Downtime] × (100) [Total source operating time]	%[2]

[1]For gases, record all times in hours.
[2]For the reporting period: If the total duration of excess emissions 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.
On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Signature

____
Title

____
Date

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ________________________________, representing the period beginning ______________________ and ending ______________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ____ ____________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title __________________________________ __________________________________
(please print or type) Name Title

Telephone No. ______________________________ Fax No. ______________________________

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[1] This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

   (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

   (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.