217/785-1705

CONSTRUCTION PERMIT/PSD APPROVAL
NSPS SOURCE - NESHAP SOURCE

PERMITTEE

Broadwing Energy Center
Attn: Jonathan Wiens, CEO
750 Town and Country Boulevard, Suite 660
Houston, Texas 77024

I.D. No.: 115015BWL
Application No.: 25040003
Date Received: April 4, 2025
Date Issued: DRAFT April 1, 2026
Subject: Cogeneration Facility
Location: N. Brush College Rd., Decatur, Macon County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission units and air pollution control equipment consisting of a cogeneration facility, as described in the above referenced application. This permit is granted based upon and subject to the findings and conditions that follow.

In conjunction with this permit, approval is given with respect to the regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the facility, as described in the application, in that the Illinois EPA finds that the application fulfills all applicable requirements of 35 IAC Part 204. This approval is issued pursuant to the federal Clean Air Act and the PSD rules at 35 IAC Part 204. This approval may be appealed in accordance with provisions of 415 ILCS 5/40.3 and 35 IAC Part 105. This approval is based upon the findings that follow. This approval is subject to the following conditions. This approval is also subject to the general requirement that the facility be developed and operated consistent with the specifications and data included in the application and any significant departure from the terms expressed in the application, if not otherwise authorized by this permit, must receive prior written authorization from the Illinois EPA.

If you have any questions on this permit, please call Joe Fraganato at 217/782-7088.

William D. Marr
Manager, Permit Section
Bureau of Air

WDM:JSF:

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<u>Findings</u>

1. a. Broadwing Energy, LLC has applied for a construction permit/Prevention of Significant Deterioration (PSD) approval to construct the Broadwing Energy Center (“Broadwing”): a new cogeneration facility, i.e., a facility that would generate electricity and steam, with a gross electrical output of approximately 452 MW at International Organization for Standardization (ISO) conditions. This cogeneration facility would be located adjacent to the Archer Daniels Midland (ADM) complex in Decatur, supplying steam and electricity to ADM’s operations.

   b. The cogeneration unit would consist of a natural gas-fired combustion turbine, heat recovery steam generator, and an electric generator. Broadwing’s cogeneration facility would be optimized for steam generation, rather than electrical output. Duct burners would be placed inside of the heat recovery steam generator to provide supplemental firing using the flue gas from the combustion turbine, which would enable additional steam production.

   c. The cogeneration unit would include an amine-based carbon capture process (CCP). The CCP would be used to separate CO_2 from the cogeneration unit’s flue gas.

   d. This project would also involve the construction of several new emission units which would support the cogeneration operations, including a cooling tower, fuel gas heater, liquid storage tanks, piping and piping equipment, a fire water pump, and emergency diesel-fired generators.

2. Broadwing’s facility would be located in Macon County, an area that is designated attainment or unclassifiable for all criteria pollutants, as provided in the Designation of Areas for Air Quality Planning Purposes for Illinois, 40 CFR 81.314.

3. a. The proposed facility would be a major source under the rules for PSD, 35 IAC Part 204. This is because the facility’s potential emissions of nitrogen oxides (NOx), carbon monoxide (CO), volatile organic material (VOM), particulate matter$_{10}$ (PM_{10}) and particulate matter$_{2.5}$ ($PM_{2.5}$) would exceed 100 tons per year, which is the applicable threshold for a major source under the PSD rules.

   b. The facility would also be a major project under PSD for sulfuric acid mist (SAM), particulate matter (PM), and greenhouse gases (GHG) because the facility’s potential emissions of each of these pollutants exceed the applicable significant emission rates under the PSD rules. (Refer to Attachment 1 for a summary of the potential emissions of the facility.)

   c. The facility would not be a major project under the PSD rules for other pollutants. This is because the potential emissions of these other pollutants would be below the applicable significant emissions rates under the PSD rules.

4. The proposed facility would be a major source for emissions of hazardous air pollutants (HAP), as the potential emissions from the facility would be 10 tons or more of an individual HAP and 25 tons or more in aggregate for total HAP. A case-by-case determination of Maximum Achievable Control Technology (MACT) under Section 112(g) of the federal Clean Air Act would not be required for the proposed facility, as all units that would emit HAP at the facility would either be subject to or specifically exempt from promulgated MACT standards.

5. Broadwing would not be considered a single source with ADM’s Decatur complex (Bureau of Air I.D. No. 115015AAE) because the proposed cogeneration facility (i) has a different standard industrial classification (SIC) code; (ii) Broadwing would own and operate the cogeneration facility, and would

be responsible for its own environmental compliance with all applicable legal requirements; and (iii) ADM would not have any ownership interest in, operational control over, or environmental compliance responsibility for Broadwing's operations. Items (ii) and (iii) above would apply identically to Broadwing's noninvolvement in ADM's Decatur complex operations.

6. After reviewing the materials submitted by Broadwing, the Illinois EPA has determined that this project would (i) comply with applicable state emission standards; (ii) comply with applicable federal emission standards; and (iii) utilize BACT on emissions units which could emit NOx, CO, VOM, SAM, GHGs, PM, PM_{10} and $PM_{2.5}$, as required by the PSD rules.

   Note: For the pollutants that are subject to PSD, the determination of BACT made by the Illinois EPA for the various emission units at the proposed facility are generally contained in the permit conditions for specific emissions units that are headed by "Control Technology Determination – BACT."

7. a. The air quality analysis prepared and provided by Broadwing for the project demonstrates that the project would not cause or contribute to violations of the National Ambient Air Quality Standards (NAAQS) for NO_2, CO, and $PM_{2.5}$. The air quality analysis also shows compliance with the applicable allowable increment levels for CO, NO_2, PM_{10}, and ozone established under the PSD rules.

   b. Other impact analyses were also submitted by Broadwing, as required by the PSD rules, to address other potential impacts from the emissions of the proposed facility, including impacts to soils and vegetation. These analyses show there would be no adverse effects.

8. A copy of the application, a summary of the Illinois EPA's review of the application and a draft of this permit were made available in a location in the vicinity of the proposed project location. The public was given notice and opportunity to examine these materials and to submit comments, and to request a public hearing on this matter.

Abbreviations and Acronyms Used in This Permit

ADM	Archer Daniels Midland Company
ADM Decatur	Archer Daniels Midland Company, Decatur Complex
BACT	Best Available Control Technology
Broadwing	Broadwing Energy Center
CAAPP	Clean Air Act Permit Program
CCP	Carbon Capture Process
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
CT	Combustion Turbine
CTG/HRSG	Combustion Turbine Generator/Heat Recovery Steam Generator
dscf	Dry Standard Cubic Feet
GHG	Greenhouse gasses, expressed as carbon dioxide (CO_2) equivalents (CO_2e)
Gr	Grains
Hr	Hour
HRSG	Heat Recovery Steam Generator
IAC	Illinois Administrative Code
Illinois EPA	Illinois Environmental Protection Agency
Lb	Pound
LDAR	Leak Detection and Repair
mmBtu	Million British Thermal Units
Mo	Month
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMHC	Nonmethane Hydrocarbon
NOx	Nitrogen Oxides
NSR	New Source Review
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 microns as measured by applicable test or monitoring methods
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns as measured by applicable test or monitoring methods
ppm	Parts per million, by volume
PSD	Prevention of Significant Deterioration (35 IAC Part 204)
scfm	Standard Cubic Feet per Minute
SO_2	Sulfur Dioxide
USEPA	United States Environmental Protection Agency
ULSD	Ultra-Low Sulfur Diesel
VOC/VOM	Volatile Organic Compounds; synonymous with Volatile Organic Material
Yr	Year

Part 1: Conditions for the Project

1.1 Effect of Permit

a. This permit does not relieve the Permittee of the responsibility to comply with all local, state and federal regulations that are part of the applicable Illinois' State Implementation Plan, as well as all other applicable federal, state and local requirements.

b. In particular, this permit does not relieve the Permittee from the responsibility to carry out practices during the construction and operation of the cogeneration facility, such as application of water or dust suppressant sprays to unpaved traffic areas, as necessary, to reduce fugitive dust and prevent an air pollution nuisance from fugitive dust, as addressed by 35 IAC 201.141.

1.2 Validity of Permit and Commencement of Construction

a. This permit shall become invalid if construction is not commenced within 18 months after this permit becomes effective, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable period of time, pursuant to 35 IAC 204.830. The Illinois EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. This condition supersedes Standard Condition 1.

b. For purposes of the above provisions, the definitions of "construction" and "commence" at 35 IAC 204.340 and 204.320 shall apply, which require that a source must enter into a binding agreement for on-site construction or begin actual on-site construction. (See also the definition of "begin actual construction," 35 IAC 204.270.)

1.3 Natural Gas Used by the Plant

a. The natural gas used as fuel in the CTG/HRSG and dewpoint heater shall be "pipeline natural gas," with a sulfur content of no more than 0.5 grains of total sulfur per 100 standard cubic feet.

b. The Permittee shall keep copies of fuel receipts from the suppliers of natural gas to the facility or other documentation for the natural gas fired in the emission units at the facility that confirms that the gas meets the criteria in the definition of pipeline natural gas in 40 CFR 72.2.

1.4 Storage Tanks

a. Nine new fixed-roof storage tanks would be constructed to serve the Carbon Capture Process (CCP) operations and the emergency engines. Three horizontal, fixed-roof tanks would be dedicated to storage of ULSD for the two emergency engines and fire pump. Six vertical, fixed-roof tanks would be ancillary to the CCP operations, storing monoethanalamine, an organic solvent. One storage tank would dedicated to storage of ammonia, however, the ammonia tank would not be a source of regulated NSR pollutants. Changes in temperature, pressure, and liquid level may result in the emission of VOM from the ULSD tanks and the monoethanolamine storage tanks. Emissions from these tanks would be uncontrolled and vented to atmosphere via pressure relief vents.

b. Control Technology Determination (BACT) for the three ULSD storage tanks and the six storage tanks serving the CCP operations:

i. Each tank shall be a fixed roof design and shall be painted white.

ii. Each tank shall be equipped and only utilize a submerged loading pipe for loading of material into the tanks.

iii. VOM emissions of the three ULSD storage tanks shall not exceed 0.01 tons/year, total.

iv. VOM emissions of the six storage tanks serving the CCP shall not exceed 0.06 tons/year, total.

c. The Permittee shall maintain the following records for each storage tank:

i. Identification of material stored.

ii. Maximum true vapor pressure of material stored, with supporting documentation.

iii. Throughput of each material stored (gallons/month and gallons/year).

iv. VOM emissions (tons/month and tons/year) with supporting documentation and calculations.

1.5 Nonapplicability Provisions

a. For pollutants other than NOx, CO, VOM, PM, PM_{10}, $PM_{2.5}$, SAM, and GHG, this permit is issued based on this project not triggering the requirements of Illinois' rules for PSD, 35 IAC Part 204. This is because the potential to emit of regulated New Source Review (NSR) pollutants other than those listed above is less than significant.

1.6 Requirements for Good Air Pollution Control Practice

a. At all times, the Permittee shall operate and maintain the new emissions units affected by this project, including associated air pollution control equipment, in a manner consistent with good air pollution control practice to minimize emissions, including periods of startup, shutdown, malfunction or breakdown, as follows:

i. Unless otherwise specified, the Permittee shall conduct monthly inspections and perform appropriate maintenance and repairs to facilitate proper functioning of emission units and minimize or prevent malfunctions and breakdowns. The Permittee shall maintain logs for these inspections in accordance with Condition 3.4(b).

ii. Install, calibrate, and maintain required monitoring devices and instrumentation in accordance with good monitoring practices, following the manufacturer's recommended operating and maintenance procedures or such other procedures as otherwise necessary to assure reliable operation of such devices.

1.7 Compliance with Emission Standards and Emission Limits

a. The emission limits set by this permit, including BACT limits and other permit limits for emissions, apply at all times unless otherwise specified in a particular provision.

b. i. Unless otherwise provided by applicable rules, emission standards for PM under applicable regulations that are referenced in the conditions of this permit address only filterable particulate.

ii. Emissions limits for PM_{10} and $PM_{2.5}$ set by this permit address both filterable and condensable particulate.

c. Emission limits for GHG set by this permit address GHG as carbon dioxide equivalents (CO_2e). For the purpose of this permit, the following global warming potential shall be used for determining CO_2e emissions:

i. CO_2: 1

ii. CH_4: 28

iii. N_2O: 265

iv. SF_6: 23,500

d. Emission limits set by this permit in pounds/million Btu (lbs/mmBtu) are in terms of the higher heating value of the fuel burned in an emission unit.

e. When emission testing is conducted, compliance with hourly limits set by this permit shall be determined from the average of three runs, each a minimum of one hour in duration.

f. For emission limits set by this permit, unless otherwise specified in a particular provision of this permit, compliance shall be determined as follows:

i. Compliance with emission limits for emission units and pollutants for which continuous emissions monitoring is required by the permit shall be determined from emission data collected by such monitoring systems and from representative emission data for periods when such systems do not provide acceptable data.

ii. Compliance with emission limits for emission units and pollutants for which continuous emission monitoring is not required shall be determined from emission data calculated as the product of activity or operating data and emission factors that do not understate emissions, as developed from representative source-specific testing or analysis, USEPA methodology or other authoritative source.

iii. Except for the annual limits in Conditions 2.1.2-1(c) and 2.1.3-1(b)(ii), compliance with annual limits established by this permit shall be calculated monthly from a running total of 12 months of data, i.e., from the sum of the data for the current month and data for the preceding 11 months (12 month total) and shall consider all emissions, including emissions during startup, shutdown, and malfunction and breakdown, provided however, that for the first year (12 months) of operation compliance shall be calculated from a cumulative total of monthly data, i.e., from the sum of the data for the current month and data for all preceding months. In addition, until emissions data is available from certified continuous emissions monitoring systems or from performance or emission testing, in lieu of such data, appropriate emission factors provided by the manufacturer or other authoritative source may be used to determine emissions.

1.8 Records for Monitoring Systems and Instrumentation

a. The Permittee shall keep records of the data measured by required monitoring systems and instrumentation. Unless otherwise provided in a particular condition of this permit, the following requirements shall apply to such recordkeeping:

i. For required monitoring systems, data shall be automatically recorded by a central data system, dedicated data logging system, chart recorder or other data recording device. If an electronic data logging system is used, the recorded data shall be the hourly average value of the particular parameter for each hour.

ii. For required instrumentation, the measured data shall be recorded manually at least once per day, unless otherwise specified, with data and time both recorded, for periods when the associated emission unit(s) are in service, provided however that if data from an instrument is recorded automatically, the provisions in Condition 1.8(a)(i) for recording of data from monitoring systems shall apply and manual recording of data is not required.

b. The Permittee shall maintain records for the operation, calibration, maintenance and repair of required monitoring systems and instrumentation. These operating records shall, at a minimum, identify the date and duration of any time when a required monitoring instrument or device was not in operation, with explanation; the performance of manual quality control and quality assurance procedures for the system; and maintenance and repair activities performed for the system.

c. The Permittee shall maintain a file containing a copy of the specifications for each required monitoring device or instrument and the recommended operating and maintenance procedures for the device as provided by its manufacturer.

1.9 Records for Opacity Measurements

a. The Permittee shall maintain records for all opacity measurements made in accordance with USEPA Method 9 for emission units at the facility that it conducts or that are conducted on its behalf by individuals who are qualified to make such observations. For each occasion on which such measurements are made, these records shall include the formal report for the measurements if conducted pursuant to this permit or a request from the Illinois EPA, or otherwise the identity of the observer, a description of the measurements that were made, the operating condition of the affected operations, the observed opacity, and copies of the raw data sheets for the measurements.

1.10 General Recordkeeping Requirements

a. Retention and Availability of Records:

i. A. Records of all monitoring data and support information shall be retained for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

B. Other records required by this permit including any logs, plans, procedures, or instructions required to be kept by this permit shall be retained for a period of at least 5 years from the date of entry unless a different period is specified by a particular permit provision.

ii. The Permittee shall retrieve and provide paper copies, or as electronic media, of any records required by this permit that are retained in an electronic format (e.g., computer) in response to an Illinois EPA request during the course of a source inspection.

1.11 General Reporting Requirements

a. The Permittee shall submit an Annual Emission Report in accordance with 35 IAC Part 254.

b. Except as specified in a particular provision of this permit, if there is any deviation or exceedance from the requirements of this permit, the Permittee shall submit a report to the Illinois EPA within 30 days after the deviation or exceedance. The report shall describe the deviation or exceedance, provide the probable cause of the deviation, the corrective actions that were taken, and any action taken to prevent future occurrences.

1.12 Addresses for the Illinois EPA

a. Reports and notifications required by this permit shall be sent to the Illinois EPA at one of the following addresses unless otherwise indicated:

Via USPS	Via Other Means
Illinois EPA, Bureau of Air Compliance Section (MC #40) 2520 West Iles Avenue P.O. Box 19276 Springfield, Illinois 62794-9276	Illinois EPA, Bureau of Air Compliance Section (MC #40) 2520 West Iles Avenue Springfield, Illinois 62704

b. One electronic copy of reports and notifications concerning emission testing or emissions monitoring shall be sent to EPA.BOA.SMU@Illinois.gov. For large files, the Permittee may request to use the Illinois EPA OneDrive Request File or another approved method. The facility's ID Number shall be included on all correspondence.

1.13 Authorization to Operate Emission Units

a. For emission units that do not require initial emissions testing (cooling tower system, dewpoint heater, emergency engines, piping and piping equipment, roadways and parking areas, circuit breakers, lube oil system and storage tanks), operation of those units is authorized under this permit until a Clean Air Act Permit Program (CAAPP) permit is issued for those units, provided that the Permittee submits a complete and timely application for a CAAPP permit for those units as provided for by Section 39.5(5) of the Environmental Protection Act.

b. For the cogeneration unit, operation is authorized under this permit:

i. For an initial period that ends on the date by which initial testing of the cogeneration unit is required by this permit. This initial period of operation may be extended by the Illinois EPA for up to an additional 365 days upon request of the Permittee if additional time is needed to complete shakedown or complete emission testing of the cogeneration unit.

ii. Following the initial period, until a CAAPP permit is issued, provided:

A. The Permittee has successfully completed the applicable emissions testing required by this permit for the cogeneration unit.

B. The Permittee has submitted a complete and timely application for a CAAPP permit that addresses the cogeneration facility including the cogeneration unit, as provided for by Section 39.5(5) of the Environmental Protection Act.

c. Conditions 1.13(a) and (b) supersede Standard Condition 6.

1.14 <u>Standard Conditions</u>

Standard conditions for issuance of construction permits, attached hereto and incorporated herein by reference, shall apply to this project, unless superseded by other conditions in the permit.

Part 2: Unit-Specific Conditions

Subpart 2.1: Combustion Turbine/Heat Recovery Steam Generator

2.1.1-1 Introduction

A new cogeneration unit would be responsible for producing steam and electricity at the facility. The cogeneration unit would consist of two interconnected, dependent processes: a natural gas-fired combustion turbine generator (CTG) working in tandem with a heat recovery steam generator (HRSG), which would be equipped with a supplemental natural gas-fired duct burner to enhance steam production levels. An evaporative cooler at the inlet of the CTG would cool the inlet air during warm weather to increase power output.

NOx emissions from the CTG/HRSG would be controlled by combustion technology (i.e., dry low-NOx (DLN) combustion), and add-on selective catalytic reduction (SCR) systems. Emissions of CO and VOM would be controlled by add-on catalytic oxidation systems.

The cogeneration unit would be equipped with an amine-based carbon capture process (CCP) capable of removing CO_2 from the flue gas of the cogeneration unit. After passing through the SCR and oxidation catalyst control system, flue gas from the cogeneration unit would be sent to the CCP. The purpose of this operation would be to strip CO_2 from the flue gas stream and prepare it to be transported by a CO_2 pipeline.

In the first stage of the CCP, hot flue gas from the cogeneration unit would pass through a direct-contact quenching column, cooling the gas stream to a temperature that is suitable for gas-liquid absorption. Nozzles placed throughout the height of the quenching column would spray cool water down the column, countercurrent to the hot exhaust gas entering near the bottom of the tower. Hot water collected from the bottom of the quencher would be processed by the new Cooling Tower (EP-3), which is addressed by Subpart 2.2.

The cooled gas would then be routed to an absorption column, comprised of two sections: the CO_2 absorption section in the lower part of the column and the treated flue gas washing section in the top portion of the column. In the first stage, exhaust gas comes into contact with the amine-based solution, stripping CO_2 from the gas stream. The exhaust gas passing through this section of the absorption column would be capable of causing evaporative and entrainment losses of the process solvent, resulting in the emission of VOM (a portion of which would be HAPs). As the exhaust gas passes up the column, emissions generated by the absorber would be controlled by a water wash and condensate recycle system, scrubbing the aerosolized portion of the amine solvent and recirculating this solvent back to the absorption column.

After absorbing CO_2 from the exhaust stream, the "CO_2 rich" solvent would be processed by the regenerator. This unit would utilize steam produced by the cogeneration unit to heat the CO_2 rich solvent, releasing CO_2 from the solution and producing a "CO_2 lean" solvent that could be sent back to the absorption column. CO_2 released at the regenerator would then be dried and compressed, and transported from the CCP, by way of a CO_2 pipeline, to ADM's existing network of sequestration wells.

2.1.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.1, the CTG/HRSG in Condition 2.1.1-1 and listed below is referred to as the "affected turbine." The absorption column contained within the carbon capture process is referred to as the "affected absorber." The affected absorber is the primary source of emissions from the carbon capture process. Collectively, the ancillary operations to the carbon capture process addressed in Condition 2.1.1-1(a) and listed below are referred to as the “affected capture process.” For the purpose of this permit, the affected capture process does not include other ancillary sources of emissions associated with the carbon capture process including a cooling tower system (Subpart 2.2), emergency engines (Subpart 2.4), piping equipment (Subpart 2.5), roadways/parking areas (Subpart 2.6), a lube oil system (Subpart 2.8) and storage tanks (Subpart 1.4).

Emission Unit/Operation	Description	Control
CTG/HRSG (EP-2)	452 MW gross electrical output at ISO conditions. Natural gas-fired cogeneration unit optimized for steam production.	DLN Combustors Ammonia-based SCR Oxidation Catalyst Amine-based Carbon Capture Process
Carbon Capture Process (EP-1)	Operations designed to strip CO_2 from the exhaust gases generated by the CTG/HRSG and prepare CO_2 stream for sequestration.	Three-stage water wash (scrubber)

2.1.2-1 <u>Control Technology Determination (BACT): CTG/HRSG</u>

a. i. Except as provided by Conditions 2.1.2-1(a)(i)(B) and (C), the affected turbine shall be equipped, operated and maintained with the following features to control or reduce emissions:

A. NOx: DLN combustors and SCR.

B. CO and VOM: Oxidation catalyst and good combustion practices.

C. PM, PM_{10} and $PM_{2.5}$: Good combustion practices.

D. Sulfuric acid mist: Good combustion practices; use of natural gas with a sulfur content of no greater than 0.5 gr/100 scf.

E. GHGs: Carbon capture, inherently lower-polluting design, good combustion practices and operational energy efficiency.

ii. The requirement to operate and maintain an SCR and oxidization catalyst in Conditions 2.1.2-1(a)(i)(A) and (B) shall not apply to the affected turbine during its shakedown period. The shakedown period for the affected turbine is defined as the period that begins with the initial startup of the affected turbine and ends no later than either the applicable date that the performance testing of the affected turbine required by Condition 2.1.7-1(a), (b) and (c) is completed or when the affected turbine engages in commercial dispatch or 180 days after the initial startup of the affected turbine, whichever occurs first. Commercial dispatch occurs when the Midwest Independent System Operator is first notified that the affected turbine is available for commercial electric power generation.

iii. The requirement to operate and maintain the carbon capture process in Condition 2.1.2-1(a)(i)(E) shall not apply to the affected turbine until shakedown of the affected capture process is complete, after which it shall not apply to the affected turbine if the affected capture process is not available pursuant to Condition 2.1.2-1(c)(ii)(A) and (B). The shakedown period for the affected capture process is defined as the period that begins with the initial startup of the affected capture process and ends after the affected capture process first meets the control requirements of Condition 2.1.2-1(c)(i) but no later than 36 months after initial startup of the affected capture process.

b. i. Except for NOx, CO and VOM emissions during a clock hour that includes startup, shutdown, tuning or shakedown, emissions of the affected turbine shall not exceed the following limits on a rolling 3-operating hour average:

Pollutant	Limit
NOx	2.0 ppmvd, adjusted to 15 percent oxygen
CO	1.5 ppmvd, adjusted to 15 percent oxygen
VOM	2.0 ppmvd, adjusted to 15 percent oxygen
PM	0.0037 lb/mmBtu
$PM_{10}/PM_{2.5}$	0.0067 lb/mmBtu
SAM	7.05 lb/hour

ii. A. During startup, shutdown, and tuning of the affected turbine, operation and hourly emissions of NOx, CO, and VOM of the affected turbine shall not exceed the following limits. The emission limits become applicable following shakedown of the affected turbine and apply for each clock hour that includes startup, shutdown or tuning of the turbine:

Event/Operation	Event Duration (Minutes)	NOx (Lbs/Event)	CO (Lbs/Event)	VOM (Lbs/Event)
Startup/Tuning	220	1,300	10,800	2,800
Shutdown	8	53	960	250

B. For the affected turbine, the total duration of startups, tuning events, and shutdowns of the turbine shall not exceed a total of 95 hours per year, 12-month rolling average. Each startup shall not exceed a total of 220 minutes, and each shutdown shall not exceed 8 minutes. These limits become effective after the shakedown period for the affected turbine is complete.

1. A startup is defined as the period of time that begins when the operational monitoring system on the turbine detects a flame or other indicator that combustion of fuel has begun in the turbine and ends 15 minutes after the temperature of the SCR inlet catalyst bed reaches 620 °F, one-minute average, or such earlier time that the Permittee determines that effective NOx control is being achieved with ammonia injection.

Note: During startup, the damper between the affected turbine and the affected capture process is closed, and all exhaust gases from the CTG/HRSG are vented through the HRSG stack, i.e., no emissions are vented to the affected capture process.

2. A shutdown period is defined as the period beginning when the affected turbine receives a "turbine stop" command from the operator and the electrical generator output drops below the minimum stable load of 200 MW gross electrical output. A shutdown ends when the turbine operational monitoring system no longer detects a flame, ceasing to record a flame detection signal in the facility's control system.

3. Tuning is the operation of the affected turbine for the purpose of calibrating operational instrumentation, adjusting operational programming, and/or adjusting the operation of combustors.

iii. During a clock hour that includes shakedown of the affected turbine, the hourly emissions of NOx, CO, and VOM of the affected turbine shall not exceed the following limits:

Operation	NOx (Pounds/Hour)	CO (Pounds/Hour)	VOM (Pounds/Hour)
Shakedown	355	2,945	764

iv. During startup, shutdown, tuning and shakedown, the Permittee shall:

A. Operate the affected turbine in accordance with good combustion practices.

B. Operate the affected turbine in accordance with written operating procedures that address startup, shutdown, tuning, and shakedown.

C. Inspect, maintain, and repair the affected turbine and associated air pollution control equipment in accordance with written maintenance procedures.

c. i. The GHG emissions of the affected turbine shall be controlled by the affected capture process, which shall be designed, operated, and maintained to achieve at least a 75% reduction in GHG emissions based on a 12-month rolling average. Any operating-hour in which Condition 2.1.2-1(c)(ii)(A) or (B) is satisfied shall not be included when calculating the 12-month rolling average.

ii. For the affected turbine, during any operating hour in which Condition 2.1.2-1(c)(ii)(A) or (B) is satisfied, the GHG emissions of the affected turbine, expressed as CO_2e, shall not exceed the following limit: 800 pounds/MW-hr gross electrical output, as an annual average of 12 consecutive operating months, rolled monthly.

A. Unavailability* of tax credits for carbon dioxide capture and sequestration provided by section 45Q of the Internal Revenue Code, at a rate of at least $85/metric ton ($77/ton) of CO_2 captured; or

B. Archer Daniels Midland Company is unable to accept pipeline CO_2 from the cogeneration facility for some or all of the operating hour due to sequestration well or CO_2 pipeline unavailability.

* Availability of tax credits means the existence of CO_2 sequestration credits, as provided by Title 26 of the United States Code, section 45Q, reflecting the revisions made by the Inflation Reduction Act of 2022 (H.R. 5376). Periods in which Broadwing is ineligible under Section 45Q for these credits do not qualify as unavailability.

C. For the purpose of demonstrating compliance with the output-based limit provided in Condition 2.1.2-1(c)(ii) above, the Permittee shall use the following equations to calculate gross energy output, MWh, of the affected turbine:

$$P_{gross} = \frac{(Pe)_{CT}}{TDF} + (Pt)_{PS}$$

Where:
P_{gross} = gross energy output of the affected turbine for each operating hour in which the limit provided by Condition 2.1.2-1(c)(ii) applies, in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power electric generating unit where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (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. Standard ambient temperature and pressures means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

$$(Pt)_{PS} = \frac{Qm \times H}{CF}$$

Where:
Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh

D. For the purpose of demonstrating compliance with the output-based limit provided in Condition 2.1.2-1(c)(ii), the Permittee shall use Equation G-4 in

Appendix G to 40 CFR Part 75 to calculate the hourly CO_2 mass emission rate from combustion, tons/hour, of the affected turbine.

E. For the purpose of demonstrating compliance with the output-based limit provided in Condition 2.1.2-1(c)(ii), the Permittee shall use the following emission factors of natural gas combustion:

1. CH_4 emission factor: 1.0×10^{-3} kg CH_4/mmBtu (2.21×10^{-3} lb CH_4/mmBtu).

2. N_2O emission factor: 1.0×10^{-4} kg N_2O/mmBtu (2.21×10^{-4} lb/mmBtu).

d. As soon as practicable following initial startup of the affected turbine and no later than commencement of commercial operation, the Permittee shall install the catalysts in the SCR and oxidation catalyst control systems for the turbine and thereafter operate and maintain these systems for control of emissions of NOx, CO, and VOM from the affected turbine. For purposes of this permit, commencement of commercial operation occurs when Broadwing begins to generate electricity for sale from the affected turbine.

2.1.2-2 Control Technology Determination (BACT): CCP

a. i. The affected capture process shall be operated and maintained with a three-stage water washing system with condensate recycle.

ii. The affected absorber shall be constructed with low carbon steel with a carbon content of no more than 0.30 percent by weight.

b. i. The VOM emissions of the affected capture process shall not exceed 115.0 lb/hr, 3-operating hour average, rolled hourly, and excluding startup and shakedown of the affected capture process.

ii. For the affected capture process, a startup consists of two independent steps:

A. Step 1 begins when the SCR in the HRSG has reached a minimum temperature of 620 °F and the damper between the affected turbine and the affected capture process is opened, and all exhaust gases from the affected turbine are vented through the affected capture process. Step 1 ends when the CO_2 compressor and dehydration unit have been started, the CO_2 pipeline valve is opened, and CO_2 has begun offsite transport through the CO_2 pipeline.

B. Step 2 begins once the CO_2 pipeline valve has been opened, and transportation of CO_2 towards underground storage begins. Step 2 ends when the carbon capture process operational conditions reach a steady state equilibrium with the exhaust gas flow rate from the affected turbine.

iii. For the affected capture process, the duration of Step 1 and Step 2 of startup shall not exceed the following limits. These limits become effective after the shakedown period for the affected capture process is complete.

A. Step 1 of startup shall not exceed 60 minutes. The total number of operating hours spent in step 1 for startups shall not exceed 25 hours per year.

B. Step 2 of startup shall not exceed 720 minutes. The total number of operating hours spent in step 2 for startups shall not exceed 300 hours per year.

iv. For the affected capture process during a clock-hour that includes a Step 1 or Step 2 of startup, as defined by Condition 2.1.2-2(b)(ii), and during shakedown, the VOM emissions of the affected capture process shall not exceed the following:

Event/Operation	VOM Limits (Pounds/Hour)
Shakedown or Step 1 of Startup	368.0
Step 2 of Startup	230.0

2.1.3-1 <u>Federal Emission Standards (NSPS)</u>

a. i. The affected turbine, including the duct burners, are subject to the NSPS for Stationary Combustion Turbines, 40 CFR 60 Subpart KKKKa, and the General Provisions of the NSPS, 40 CFR Subpart A. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA.

ii. The affected turbine is subject to 40 CFR 60.8(c), 60.4320a(a), and Table 1 of 40 CFR Subpart KKKKa, which states that NOx emissions from the affected turbine shall comply with one of the following limits. These limits apply at all times, including periods of startup, shutdown, and malfunction, as defined by 40 CFR 60.2.

A. 5 ppm corrected to 15 percent O_2 in the exhaust or 7.9 ng/J useful output (0.018 lb/mmBtu), on a 4-operating hour rolling average; or

B. 0.054 kg/MWh-gross (0.12 lb/MWh-gross) or 0.055 kg/MWh-net (0.12 lb/MWh-net), on a 30-operating day rolling average; or

C. While the affected turbine is operating at less than 70 percent of the base load rating: 96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/mmBtu).

iii. The affected turbine is subject to 40 CFR 60.4320a(b), which provides that compliance with the applicable NOx emission standard given by Table 1 of 40 CFR 60 Subpart KKKKa shall be determined by meeting the requirements specified in 40 CFR 60.4320a(b)(1) through (4), as applicable.

iv. The affected turbine is subject to 40 CFR 60.4330a(a), which provides that SO_2 emissions from the affected turbine shall comply with one of the following limits:

A. Emissions shall not exceed 0.90 lb/MW-hr gross output; or

B. The total potential emissions shall not exceed 0.060 lb SO_2/mmBtu heat input.

v. The affected turbine is subject to 40 CFR 60.11(d) and 60.4333a(a), which provide that at all times, including periods of startup, shutdown, and malfunction, the Permittee must operate and maintain the affected turbine, including associated air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

vi. The affected turbine is subject to 40 CFR 60.4333a(d), which provides that the affected turbine shall demonstrate compliance with the SO_2 emissions standard in 40 CFR 60.4330a using one of the methods specified in 40 CFR 60.4333a(d)(1) through (4).

vii. The affected turbine is subject to 40 CFR 60.4333a(e), which provides that the Permittee shall determine compliance with the applicable NOx and SO_2 emission standards of 40 CFR Subpart KKKKa according to the procedures in 40 CFR 60.4333a(e)(1) or (2), as applicable.

b. i. The affected turbine is subject to the NSPS for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60 Subpart TTTTa, and for purposes of 40 CFR 60 Subpart TTTTa, the related requirements of the General Provisions of the NSPS specified in Table 3 of 40 CFR 60 TTTTa.

ii. Pursuant to 40 CFR 60.5520a(a), 60.5525a(a), and Table 1 of 40 CFR 60 Subpart TTTTa, the CO_2 emissions of the affected turbine on a 12-month rolling average shall not exceed the following limits, with compliance determined pursuant to 40 CFR 60.5540a:

A. For 12-operating month averages beginning before January 2032, 800 lb CO_2/MW-hr of gross energy output.

B. For 12-operating month averages beginning after December 2031, 100 lb CO_2/MW-hr.

iii. The affected turbine is subject to 40 CFR 60.5525a(b), which provides that the Permittee must at all times operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice.

iv. The affected turbine is subject to 40 CFR 60.5540a(a), which provides that the Permittee must demonstrate compliance with the applicable CO_2 emission standard in table 1 to 40 CFR 60 Subpart TTTTa as required in 40 CFR 60.5540a. For the initial and each subsequent 12-operating-month rolling average compliance period, the Permittee must follow the procedures in 40 CFR 60.5540a(a)(1) through (8) to calculate the CO_2 mass emissions rate for the affected turbine in units of the applicable emissions standard, i.e., lb/MWh. The Permittee must use the hourly CO_2 mass emissions calculated under 40 CFR 60.5535a(b) or (c), as applicable, and the generating load data from 40 CFR 60.5535a(d)(1).

v. The affected turbine is subject to 40 CFR 60.5525(c), which provides that 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 the affected turbine with respect to the applicable emissions standard in table 1 to 40 CFR 60 Subpart TTTTa, in accordance with the requirements in this 40 CFR 60 Subpart TTTTa. The first operating month included in the initial 12-operating-month compliance period shall be determined in accordance with 40 CFR 60.5525a(c)(1) through (3).

2.1.3-2 Federal Emission Standards (NESHAP)

a. i. The affected turbine is subject to the NESHAP for Stationary Combustion Turbines, 40 CFR 63 Subpart YYYY, and the related requirements of the General Provisions of the NESHAP specified in Table 7 of 40 CFR 63 Subpart YYYY.

ii. The affected turbine is subject to 40 CFR 63.6100, which provides that the Permittee must comply with the emission limitations and operating limitations in Table 1 and Table 2 of 40 CFR 63 Subpart YYYY.

iii. The affected turbine is subject to 40 CFR 63.6105(a), which provides that the Permittee must be in compliance with the emission limitations, operating limitations, and other applicable requirements in 40 CFR 63 Subpart YYYY at all times.

iv. The affected turbine is subject to 40 CFR 63.6105(c), which provides that the Permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

v. The affected turbine is subject to 40 CFR 63.6125(a), which provides that the Permittee must monitor on a continuous basis the oxidation catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of 40 CFR 63 Subpart YYYY.

2.1.3-3 State Emission Standards

a. i. The affected turbine is subject to 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any subject emissions unit, except as allowed by 35 IAC 212.123(b) or 212.124.

ii. Notwithstanding the above, during periods when fuel is being fired in duct burners in the affected turbine, the affected turbine is subject to 35 IAC 212.122(a), which limits opacity to 20 percent except as allowed by 35 IAC 212.122(b) or 212.124(a).

b. The affected turbine is subject to 35 IAC 217.706, which provides that no person shall cause or allow the emissions of NOx into the atmosphere from a subject combustion turbine to exceed 0.25 lb/mmBtu of actual heat input during each ozone control period (i.e., the period of May 1 through September 30 in each calendar year, inclusive), based on a control period average for that unit.

2.1.3-4 Applicable Programs for Allowance Trading

a. The affected turbine is an affected unit under the Acid Rain Control Program Pursuant to Title IV of the Clean Air Act and are subject to certain requirements pursuant to 40 CFR Parts 72, 73, and 75.

b. The affected turbine qualifies as an Electrical Generating Unit (EGU) for purposes of the Cross-State Air Pollution Rule (CSAPR), i.e., 40 CFR Part 97. As such, the Permittee must hold allowances for the NOx and SO_2 emissions of the affected turbine during each calendar year and, for NOx emissions, during the seasonal control period.

2.1.4 Nonapplicability Provisions

a. This permit is issued based on the affected turbine not being subject to the NSPS for Stationary Gas Turbines, 40 CFR 60 Subpart GG. This is because, pursuant to 40 CFR 60.4305(b), stationary combustion turbines regulated under 40 CFR 60 Subpart KKKK are exempt from the requirements of 40 CFR 60 Subpart GG.

b. This permit is issued based on the HSRGs and associated duct burners not being subject to the NSPS for Electric Utility Steam Generating Units, 40 CFR 60 Subpart Da. This is because, pursuant to 40 CFR 60.4305(b), heat recovery steam generators and duct burners regulated under 40 CFR 60 Subpart KKKK are exempted from the requirements of 40 CFR 60 Subparts Da, Db, and Dc.

c. This permit is issued based on the affected capture process not being subject to the NESHAP for Stationary Gas Turbines, 40 CFR 63 Subpart YYYY. This is because, pursuant to 40 CFR 63.6085(a), control equipment for stationary combustion turbines are exempt from the requirements of 40 CFR 63 Subpart YYYY.

d. This permit is issued based on the affected capture process not being subject to the Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Section 112(g) and 112(j), 40 CFR 63 Subpart B. This is because, pursuant to 40 CFR 63.40(b), the requirements of 40 CFR 63.40 through 63.44 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to Sections 112(d), 112(h), or 112(j) of the Clean Air Act incorporated into another subpart of 40 CFR Part 63. As the affected capture process has been specifically exempted from the requirements of 40 CFR 63 Subpart YYYY, it is also exempt from the case-by-case MACT requirements of 40 CFR 63.40 through 63.44.

2.1.5 Operational Requirements and Limits

a. The fuel usage of the affected turbine shall not exceed 4.83 million mmBtu/month and 48.3 million mmBtu/yr.

b. At all times, including periods of startup, shutdown, tuning, and shakedown, the Permittee shall, to the extent practicable, maintain and operate the affected turbine, including associated air pollution control equipment, in manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on available information, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the affected turbine.

2.1.6-1 Hourly Emission Limits

a. Hourly emissions of SO_2, individual HAP and total HAP from the affected turbine shall not exceed the following limits on a rolling 3-operating hour average basis:

Pollutant	Limits

	(Pounds/Hour)
SO_2	7.67
Individual HAP	1.35
Total HAPs	3.10

b. i. The hourly emissions of HAPs from the affected capture process shall not exceed the following limits. These hourly limits apply to the affected capture process on a 3-operating hour average basis. These limits apply to operation of the affected capture process other than a clock-hour that includes startup or shakedown of the capture process.

Pollutant	Limits (Pounds/Hour)
Individual HAP	49.6
Total HAPs	63.7

ii. For the affected capture process during a clock-hour that includes a Step 1 or Step 2 of startup, as defined by Condition 2.1.2(b)(ii), and during shakedown of the affected capture process, the HAP emissions of the affected capture process shall not exceed the following limits:

Event/Operation	Individual HAP Limits (Pounds/Hour)	Total HAP Limits (Pounds/Hour)
Shakedown or Step 1 of Startup	158.72	203.84
Step 2 of Startup	99.2	127.4

2.1.6-2 <u>Annual Emission Limits</u>

a. The annual emissions of the affected turbine, including startup, shutdown and tuning but excluding shakedown, in total, shall not exceed the following limits:

Pollutant	Limits (Tons/Year)
NOx	218.39
CO	238.98
VOM	107.32
SO_2	33.61
PM	89.51
$PM_{10}/PM_{2.5}$	162.09
SAM	30.87
Individual HAP	5.89
Total HAP	13.57
GHGs (as CO_2e)	2,982,650

b. The annual emissions of the affected capture process, including startup but excluding shakedown, in total, shall not exceed the following limits:

Pollutant	Limits (Tons/Year)
VOM	542.80
Individual HAP	234.11

Total HAP	300.66

2.1.7-1 Testing Requirements

a. Pursuant to the NSPS, 40 CFR 60.8, the Permittee shall have performance tests conducted for the affected turbine for emissions of NOx and SO_2 in accordance with 40 CFR 60.8 using applicable methods and procedures specified by 40 CFR 60.4405a and 60.4415a.

b. Pursuant to the NESHAP, 40 CFR 63.7, the Permittee shall have performance tests conducted for the affected turbine for emissions of formaldehyde in accordance with 40 CFR 63.7 using applicable methods and procedures specified by 40 CFR 63.6120.

c. The Permittee shall have tests conducted for the affected turbine at its expense by an independent testing service.

i. These tests shall be conducted while the affected turbine is operating in its maximum operating range and other representative operating conditions.

ii. A. Testing shall be conducted for emissions of VOM, PM, PM_{10}/$PM_{2.5}$, SO_2, SAM, and HAPs using the methods provided by Condition 3.1(a).

B. For purposes of testing for HAPs from the affected turbine, testing shall be performed for emissions of formaldehyde, toluene, xylene, and acetaldehyde.

iii. This testing shall be conducted by the following dates:

A. Initial testing shall be conducted within 180 days of the initial startup of the affected turbine unless the Illinois EPA extends the shakedown period as provided for by Condition 1.13(b)(i), in which case initial testing shall be completed by the end of the extended shakedown period.

B. Thereafter, until a CAAPP permit is issued that addresses periodic testing of the affected turbine, periodic testing of the affected turbine shall be conducted at least once every 60 months.

d. The Permittee shall have tests conducted for the affected absorber at its expense by an independent testing service.

i. These tests shall be conducted while the affected turbine is operating in its maximum operating range and other representative operating conditions.

ii. A. Testing shall be conducted for emissions of VOM and HAPs, using the methods provided by Condition 3.1(a).

B. For purposes of testing for HAPs from the affected absorber, testing shall be performed for emissions of formaldehyde, acetaldehyde, and diethanolamine.

C. For purpose of demonstrating compliance with Conditions 2.1.2-2(b)(i) and 2.1.6-1(b)(i), emissions of VOM and HAP from the affected turbine, which pass through the affected absorber, shall be subtracted from the measured rates provided by the testing required by this condition.

iii. This testing shall be conducted by the following dates:

A. Initial testing shall be conducted within 180 days of the initial startup of the affected absorber unless the Illinois EPA extends the shakedown period as provided for by Condition 1.13(b)(i), in which case initial testing shall be completed by the end of the extended shakedown period.

B. Thereafter, until a CAAPP permit is issued that addresses periodic testing of the affected absorber, periodic testing of the affected absorber shall be conducted at least once every 60 months.

e. i. Testing for the affected turbine and the affected absorber shall be conducted in accordance with the testing requirements provided by Condition 3.1.

ii. The Permittee shall submit test plans, test notifications, and test reports to the Illinois EPA in accordance with Condition 3.1(b) through (d). In addition to other required information, if test runs that are longer than one hour in duration are planned, the expected duration of the runs and the reason for extended runs shall be explained in the test plans and test reports. The test reports shall include information on the heat and sulfur content of fuel that is representative of the fuel burned during the period of testing.

2.1.7-2 <u>Visual Determinations of Opacity</u>

a. The initial visual determination of opacity shall be conducted in accordance with Condition 3.2 by no later than the initial testing for PM emissions required by Condition 2.1.7-1(c).

b. Thereafter, visual determinations of opacity shall be conducted in accordance with Condition 3.2 in each calendar year unless: 1) the visual determination of emissions conducted for the affected turbine in accordance with Condition 2.1.7-3 during the previous year show that visual emissions were "normally not present" when the affected turbine was operating; or 2) the measured opacity of emissions during visual determination of opacity conducted pursuant to this condition during the previous year were not more than 5.0 percent, six-minute average.

2.1.7-3 <u>Visual Determinations of Emissions</u>

a. If the Permittee elects to show that visible emissions were "normally not present" during the operation of the affected turbine in a calendar year for purposes of Condition 2.1.7-2(b), the Permittee shall have conducted visual determinations of emissions for the affected turbine during representative operating conditions in accordance with Method 22 as follows.

i. For such calendar year, the Permittee shall have conducted a visual determination of emissions for the affected turbine in each quarter in which the turbine operated on more than five operating days.

ii. The duration of each of these determinations shall have been 18 consecutive minutes and visual emissions shall be considered to have normally not been present during an determination if the total duration of visual emissions during the determination did not exceed one minute (60 seconds).

iii. Notwithstanding Condition 2.1.7-3(a)(ii), if the total duration of visual emissions during the first 10 minutes of an observation did not exceed 20 seconds, the observation may be concluded and visual emissions shall be considered to have normally not been present during this particular observation.

b. If the criteria for visual emissions to be normally not present were met by each of the required determinations in a calendar year, visual emissions are considered to have normally not been present during the operation of the affected turbine in that year.

c. If the Permittee elects to conduct visual determinations of emissions pursuant to this condition, the Permittee shall keep the following records.

i. Records for the individual observations for visual emissions, which shall be kept for the observations that are conducted in a year even if the Permittee ceases to conduct further observations in such year, as could occur when an observation does not meet the criteria for visible emissions to be "normally not present." These records shall include:

A. Date and time of observation(s).

B. Name and employer of observer.

C. Description of weather conditions during the observation.

D. Description of the operating conditions of the operation or unit observed.

E. Determinations of the presence of visual emissions.

F. Conclusions.

ii. If the Permittee considers that these determinations show that visual emissions were "normally not present," records for the operation of the affected turbine to confirm that an observation was conducted for emissions of the turbine in each calendar quarter for which an observation was required and confirmation that these observations were appropriately conducted and the duration of visual emissions during each required observation was such that the criterion for visual emissions to be normally not present were met.

2.1.8-1 <u>Emission Monitoring Requirements</u>

a. i. For the affected turbine, the Permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for NOx emissions on the HRSG stack and affected absorber stack in accordance with the applicable monitoring requirements of 40 CFR 60.4333a(c), the federal Acid Rain Program, 40 CFR Part 75, and the Cross-State Air Pollution Rule, 40 CFR 96 Subpart HHH.

ii. A. Except during shakedown, for the affected turbine, this monitoring shall also be used to determine compliance with the limits for NOx emissions in Conditions 2.1.2-1(b)(i) and (ii).

B. During shakedown, for the affected turbine, this monitoring shall also be used to determine compliance with the limits for NOx emissions in

Conditions 2.1.2-1(b)(iii) after the NOx CEMS is installed and certified in accordance with 40 CFR 60.4345a.

C. The provisions for substitution of missing data shall not be used.

b. i. For the affected turbine, the Permittee shall install, calibrate, maintain, and operate CEMS for CO emissions on the HRSG stack and affected absorber stack in accordance with the relevant monitoring requirements of 40 CFR 60.13. Quality assurance for this CEMS shall be in accordance with Appendix B to 40 CFR Part 75, Quality Assurance and Control Procedures.

ii. A. Except during shakedown, for an affected turbine, this monitoring shall be used to determine compliance with the limits for CO emissions in Conditions 2.1.2-1(b)(i) and (ii).

B. During shakedown, for the affected turbine, this monitoring shall also be used to determine compliance with the limits for CO emissions in Conditions 2.1.2-1(b)(iii) after the CO CEMS is installed and certified in accordance with 40 CFR 60.13.

c. In addition to meeting relevant regulatory requirements for NOx and CO, the CEMS required by Condition 2.1.8-1(a) and (b) shall be equipped and operated as “dual range” monitors if it is necessary to provide credible emission data during startup and shutdown of the turbine.

2.1.8-2 <u>Operational Monitoring</u>

a. i. The Permittee shall install, operate, and maintain continuous operational monitoring systems on the affected turbine’s SCR system to measure the following operating parameters:

A. The inlet temperature to the system.

B. The reagent injection rate to the system.

ii. The Permittee shall install, operate, and maintain continuous operational monitoring systems on the affected turbine’s oxidation catalyst system to measure the operating temperature.

iii. The Permittee shall install, operate, and maintain continuous operational monitoring systems on the affected absorber for following parameters.

A. Absorbent flow rate (gallons/min).

B. Exhaust gas outlet temperature (°F).

C. Recirculation water temperature at the first stage of the water wash section of the absorber (°F).

D. Outlet gas flow rate (scfm).

iv. A. The monitoring systems required by Condition 2.1.8-2(a)(i) – (iii) shall monitor and record discrete data at least once every minute with data averaged on an hourly block basis. For purposes of reporting deviations, a deviation is not considered to have occurred during a clock-quarter unless there are no data points recorded for 15 consecutive minutes.

B. In addition to recording the data collected by systems required by Condition 2.1.8-2(a)(i) – (iii), the Permittee shall also maintain records for maintenance and operational activity associated with these systems and for outages of these systems.

b. i. The Permittee shall establish and maintain appropriate set points or ranges, as applicable, for the operating parameters specified for the monitoring systems required by Condition 2.1.8-2(a)(i) – (iii).

A. Prior to the date of testing required by Condition 2.1.7-1, these set points and ranges shall be based on manufacturer's recommendations.

B. After the date of testing required by Condition 2.1.7-1, these set points and ranges shall be determined based on operating data during the most recent compliant emissions test required by Condition 2.1.7-1 and shall be established on an hourly block average.

ii. The Permittee shall install, operate, and maintain a visible and/or audible warning system that identifies when an operating parameter is not within its established operating range.

iii. If the operating parameter is not within the established set point or range, the Permittee shall promptly investigate the cause of the variation and return it within the established operating range.

c. The Permittee shall install, operate and maintain a continuous operational monitoring system that monitors the mass flow rate of CO_2 in the CO_2 pipeline from the regenerator. This monitoring device shall monitor and record discrete data at least once every minute with data averaged on an hourly basis. For purposes of reporting deviations, a deviation is not considered to have occurred during a clock-quarter unless there are no data points recorded for 15 consecutive minutes.

d. The Permittee shall equip the affected absorber with features that enable it to readily identify an increase in the gas flow rate to the absorber, such as a device to measure gas flow rate, or otherwise conduct periodic measurements to identify an increase in the gas flow rate to the affected absorber. For this purpose, such measurements may be direct measurements of gas flow or indirect measurements of parameters, such as oxygen content, that would indicate an increase in the gas flow rate of the absorber. Measurements shall be made on at least a quarterly basis and after any significant maintenance or repair or other activity that could increase the gas flow rate to the affected absorber.

e. i. The affected turbine is subject to 40 CFR 60.5535a(c)(1), which provides that the Permittee must implement the applicable procedures in Appendix D to 40 CFR Part 75 to determine hourly heat input rates (MMBtu/h) for the affected turbine, based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

ii. The affected turbine is subject to 40 CFR 60.5535a(c)(2), which provides that for each measured hourly heat input rate, the Permittee shall use Equation G-4 in

Appendix G to 40 CFR Part 75 to calculate the hourly CO_2 mass emission rate (tons/h).

f. The affected turbine is subject to 40 CFR 60.5535a(d)(1), which provides that the Permittee must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected turbine. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see 40 CFR 60.17). The Permittee must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output.

2.1.9 Recordkeeping Requirements

a. i. For the affected turbine, the Permittee shall comply with the applicable recordkeeping requirements of the NSPS, 40 CFR 60 Subparts A, KKKKa, and TTTTa.

ii. For the affected turbine, the Permittee shall comply with the applicable recordkeeping requirements of the NESHAP, 40 CFR 63 Subparts A and YYYY.

iii. For the affected turbine, the Permittee shall comply with the applicable recordkeeping requirements of 35 IAC 217.712.

b. For the affected turbine, the Permittee shall maintain a file or other records that include:

i. The manufacturer's data for the affected turbine for emissions and rated heat input capacity (mmBtu/hour) and operating and maintenance procedures suggested by the manufacturer.

ii. Documentation for the rated output of the electrical generator associated with the affected turbine (MWe at ISO conditions). For this purpose, ISO conditions shall mean 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.325 kilopascals (14.69 psi, 1 atm) pressure.

iii. The Permittee's established startup, shutdown, and shakedown procedures for the affected turbine.

c. The Permittee shall maintain the following records for the affected turbine:

i. An operating log or other records that include:

A. The information specified by Condition 3.4(a); and

B. An identification of each operating mode for each hour of operation including:

1. Normal;

2. Shakedown;

3. Startup;

4. Shutdown; and

5. Tuning

ii. An inspection, maintenance and repair log that includes the information specified by Condition 3.4(b).

d. The Permittee shall maintain records of the following information for the affected turbine:

i. The following information for fuel usage:

A. Fuel usage for the affected turbine (mmBtu/month and mmBtu/year).

B. Fuel usage for the duct burner (mmBtu/month and mmBtu/year).

C. Total fuel usage considering the affected turbine including the duct burner (mmBtu/month and mmBtu/year).

ii. The total hours of operation for the affected turbine (hours/month and hours/year).

iii. The following information related to startup and shutdown of the affected turbine:

A. The total number of startups (startups/month).

B. For each startup, the date and time that the startup began and the duration of the startup (minutes).

C. For each shutdown, the date and time that the shutdown began and the duration of the shutdown (minutes).

D. The total duration of startups and shutdowns (hours/month and hours/year).

iv. The following information related to tuning of the affected turbine:

A. For each period when tuning was conducted, the date and time that operation of the affected turbine began and the total duration of tuning (minutes).

B. The total duration of tuning (hours/month and hours/year).

v. The total duration of startup, shutdown and tuning events (hours/month and hours/year).

vi. The following information related to electrical output of the affected turbine:

A. The gross electrical output (MW-hr/month and MW-hr/year).

B. If the Permittee is complying by means of a limit that is in terms of the net electrical output of the affected turbine, the net electrical output (MW-hr/month and MW-hr/year).

e. The Permittee shall maintain records of the following information related to the emissions of the affected turbine:

i. A file containing the maximum emission rates and the emission factors used by the Permittee to determine the emissions of different pollutants from the affected turbine for different modes of operation (as identified by Condition 2.1.9(c)(i)(B)), with supporting documentation:

A. For VOM, PM, $PM_{10}/PM_{2.5}$, SO_2, SAM, N_2O, CH_4 and HAPs, information addressing all modes of operation of the affected turbine.

B. For NOx and CO, information addressing operation of the affected turbine during the period before the CEMS are certified and during any subsequent period when emissions of the pollutant cannot be appropriately determined from data collected by a CEMS.

ii. The emissions of NOx and CO of the affected turbine, as measured by the required continuous emission monitoring systems (see Conditions 2.1.8-1(a) and (b)), in the following terms, except that, during shakedown, emissions shall be determined, in order of preference, by monitoring in accordance with Condition 2.1.8-1 or by using emission factors developed from manufacturer's data:

A. Emissions in ppmvd at 15 percent oxygen to address the limits in Conditions 2.1.2-1(b)(i) that apply to the affected turbine during periods other than startup, shutdown, tuning or shakedown.

B. Emissions in pounds/event to address the limits in Conditions 2.1.2-1(b)(ii) that apply to operation of the affected turbine during periods of startup, shutdown or tuning.

C. Emissions in pounds per hour to address the applicable limits in Condition 2.1.2-1(b)(iii) that apply to the affected turbine during periods of shakedown.

iii. The monthly and annual emissions of NOx, CO, PM, $PM_{10}/PM_{2.5}$, VOM, SO_2, sulfuric acid mist, individual HAP and total HAPs of the affected turbine (tons/month and tons/year), with supporting documentation and calculations. These records shall include emissions during startup, shutdown, and tuning.

iv. For CO_2 emissions of the affected turbine:

A. The CO_2 emissions of the affected turbine (tons/month and tons/year), with supporting documentation and calculations.

B. The CO_2 emission rate of the affected turbine (lb/MWh gross or net energy output, annual average), with supporting data and calculations.

v. For emissions of GHGs of the affected turbine, as CO_2e:

A. The GHG emissions of the affected turbine based on the operational monitoring for fuel consumption (scf/month and scf/year), and considering emissions of CO_2, N_2O and CH_4 (tons/month and tons/year), with supporting documentation and calculations.

B. The actual GHG emission rate of the affected turbine, as CO_2e, in lb/MW-hr, annual average, with supporting data and calculations.

f. The Permittee shall maintain the following records for shakedown of the affected turbine:

i. Records for the affected turbine that include the operating and maintenance procedures utilized by the Permittee to minimize emissions.

ii. For NOx, CO and VOM, a file containing the maximum hourly emission rates and the emission factors used by the Permittee to determine the emissions of each pollutant, with supporting documentation.

iii. Duration of the shakedown period for the affected turbine (days).

g. The Permittee shall maintain the following records related to the emissions of VOM and HAP from the affected capture process:

i. A file containing the emission factors that the Permittee uses to calculate emissions, with supporting documentation.

ii. The emissions of the affected capture process based on operating data and applicable emission factors (tons/month and tons/year), with supporting calculations.

h. The Permittee shall maintain the following records for the affected capture process:

i. An operating log or other records that include:

A. The information specified by Condition 3.4(a); and

B. An identification of each operating mode for each hour of operation including:

1. Normal;

2. Shakedown;

3. Startup; and

4. Shutdown.

ii. An inspection, maintenance and repair log that includes the information specified by Condition 3.4(b).

iii. Records for the amount of exhaust gas processed by the affected capture process (tons/month) and (tons/year, total).

iv. Records for the operational parameter set points or ranges required by Condition 2.1.8-2(e), established during the most recent stack test for the affected capture process.

i. The Permittee shall maintain records of the following information for the affected capture process:

i. The amount of carbon dioxide captured on an annual basis (tons/year).

ii. The electrical power consumption of the affected capture process (MW-hr/year).

j. For the affected capture process, the Permittee shall maintain the following records to demonstrate compliance with Condition 2.1.2-1(c)(i):

i. A. Operating hours for the affected capture process (hours/month and hours/year).

B. Operating hours in which Archer Daniels Midland Company is unable to accept pipeline CO_2 from the cogeneration facility due to sequestration well or CO_2 pipeline unavailability (hours/month and hours/year).

ii. Calculated mass flow rate of CO_2, N_2O and CH_4, pursuant to Conditions 2.1.2-1(c)(ii)(D) and (E).

iii. Mass flow rate of CO_2 in the CO_2 pipeline as monitored pursuant to Condition 2.1.8(c).

iv. Annual reduction in GHG emissions (percent) calculated by dividing the annual percentage of GHG emissions captured for sequestration (i.e., total mass of CO_2 captured by the affected capture process) by the total GHG emissions generated by the affected turbine using the data collected in Conditions 2.1.9(j)(i), (ii) and (iii), based on a 12-month rolling average.

2.1.10 <u>Notification and Reporting Requirements</u>

a. For the affected turbine, the Permittee shall comply with the applicable notification and reporting requirements of the NSPS, 40 CFR 60 Subparts A, KKKKa and TTTTa.

b. For the affected turbine, the Permittee shall submit the applicable notifications and reports required by the NESHAP, 40 CFR 60 Subparts A and YYYY provided by 40 CFR 63.6145 and 63.6150.

c. For the affected turbine, the Permittee shall comply with the applicable reporting requirements of 35 IAC 217.712.

d. The Permittee shall notify the Illinois EPA of deviations or exceedances of the affected turbine or the affected capture process with the permit requirements in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

e. For the affected turbine, the Permittee shall notify the Illinois EPA within 30 days of the date that the performance testing of the affected turbine required by Condition 2-1.7-1(a) has been completed or the date that the affected turbine engages in commercial dispatch, whichever occurs first.

f. i. For the affected turbine, the Permittee shall notify the Illinois EPA within 30 days of the date that it commences commercial operation of the turbine.

ii. For the affected capture process, the Permittee shall notify the Illinois EPA within 30 days of the date that it first operates the capture process following shakedown of the capture process.

Subpart 2.2: Cooling Tower System

2.2.1-1 Introduction

A new Cooling Tower consisting of 12 individual cells would be constructed, cooling process water from several operations contained within the carbon capture process. The cooling tower would have the potential to emit PM, PM_{10} and $PM_{2.5}$ from solids that are entrained in the process water that is recirculated in the tower system and CCP. Particulate emissions from the cooling tower would be controlled by drift eliminators, which collect water droplets caught in the air stream used to cool the process water.

2.2.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.2, the cooling tower described in Condition 2.2.1-1 and listed below is referred to as the "affected cooling tower."

Emission Unit	Description	Control
Cooling Tower (EP-3)	Processing water from the CCP quencher, absorber water wash, lean amine cooler, and CO_2 compressor.	Drift Eliminators

2.2.2 Control Technology Determination (BACT)

a. The affected cooling tower shall be a wet cooling tower equipped, operated, and maintained with high efficiency drift eliminators designed to limit the loss of water droplets from the unit to no more than 0.0005 percent of the circulating water flow.

b. The total dissolved solids (TDS) content of the water used in the affected cooling tower shall not exceed 2,744 mg/l, monthly average.

2.2.3 State Emission Standards

a. The affected cooling tower is subject to the state emission standard for emissions of particulate matter from process emission units of 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit, except as provided by 35 IAC 212.123(b) and 35 IAC 212.124.

b. The affected cooling tower is subject to the state emission standard for emissions of fugitive particulate matter of 35 IAC 212.301, which provides that no person shall cause or allow the emission of fugitive particulate matter from any process, including any material handling or storage activity, that is visible by an observer looking generally toward the zenith at a point beyond the property line of the source.

c. The affected cooling tower is subject to the state emission standard for particulate matter emissions of 35 IAC 212.321(a), which provides that no person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any new process emission unit in which, either alone or in combination with the emission of particulate matter from all other similar process emission units for which construction or modification commenced on or after April 14, 1972, at a source or premises, exceeds the allowable emissions rates as specified in 35 IAC 212.321(c).

2.2.4 Nonapplicability Provisions

This permit is issued based on the affected cooling tower not being subject to the NESHAP for Industrial Process Cooling Towers, 40 CFR 63 Subpart Q. This is because the affected cooling tower would not be operated with chromium-based water treatment chemicals, pursuant to 40 CFR 63.400(a).

2.2.5 Work Practice Requirements

a. i. Chromium based water treatment chemicals shall not be used in the affected cooling tower.

ii. Only non-VOM containing additives shall be used in the affected cooling tower.

b. The Permittee shall operate and maintain the affected cooling tower, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

2.2.6-1 Operational Limits

a. The circulating water flow rate of the affected cooling tower shall not exceed 167,866 gallons/minute.

2.2.6-2 Emission Limits

a. Emissions from the affected cooling tower shall not exceed the following limits.

Pollutant	Monthly Limits (Tons/Mo)	Annual Limits (Tons/Year)
PM	0.51	5.05
PM_{10}	0.27	2.69
$PM_{2.5}$	0.001	0.013

2.2.7 Sampling and Analysis Requirements

a. The Permittee shall sample and analyze the water being circulated in the affected cooling tower on at least a monthly basis for the TDS content. Measurements of the TDS content in the wastewater discharge associated with the affected cooling tower, as required by a National Pollution Discharge Elimination System (NPDES) permit issued by the Illinois EPA Bureau of Water, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce its TDS content.

b. Upon written request by the Illinois EPA, the Permittee shall promptly have the water circulating in the affected cooling tower sampled and analyzed for the presence of hexavalent chromium in accordance with the procedures of 40 CFR 63.404(a) and (b).

2.2.8 Recordkeeping Requirements

a. For the affected cooling tower, the Permittee shall maintain a file that contains documentation for:

i. The maximum design circulation rate (gallons/minute) of the affected cooling tower.

ii. The maximum design drift loss (percent) from the drift eliminators on the affected cooling tower.

iii. The supplier's recommended procedures for inspection and maintenance of the drift eliminators.

iv. A demonstration that the affected cooling tower will comply with 35 IAC 212.321(a) at the maximum process weight rate at which it would be operated.

b. The Permittee shall maintain records of:

i. Sampling and analyses of the TDS content of water circulating in the affected cooling tower (ppm, on a monthly basis) conducted pursuant to Condition 2.2.7(a).

ii. Additives or treatment chemicals used in the affected cooling tower.

iii. Operating log(s) in accordance with Condition 3.4(a).

iv. Inspection, maintenance, and repair log(s) in accordance with Condition 3.4(b).

c. The Permittee shall maintain records for the emissions of PM, PM_{10} and $PM_{2.5}$ of the affected cooling tower (tons/month and tons/year), with supporting documentation and calculations.

2.2.9 <u>Reporting Requirements</u>

a. The Permittee shall notify the Illinois EPA of deviations or exceedances of the affected cooling tower with the permit requirements in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

Subpart 2.3: Dewpoint Heater

2.3.1-1 Introduction

A natural gas-fired Dewpoint Heater would be used to indirectly heat the natural gas stream sent to the Combustion Turbine Generator. The fuel being fed to the turbine is heated to a temperature above the dew point for hydrocarbons to prevent the formation of liquid droplets in the fuel, which could cause corrosion of the turbine combustion chamber and/or turbine blade components.

2.3.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.3, the Dewpoint Heater described in Condition 2.3.1-1 and listed below is referred to as the "affected heater."

Emission Unit	Description	Control
Dewpoint Heater (EP-4)	New CT/HRSG Process Heater (17.6 mmBtu/hr)	Ultra Low-NOx Burners

2.3.2 Control Technology Determination (BACT)

a. i. The affected heater shall include an energy efficient heater design that includes appropriate insulation to retain heat within the unit.

ii. The affected heater shall be operated and maintained in accordance with good combustion practices.

iii. The affected heater shall be equipped with ultra-low-NOx burners.

b. i. The only fuel fired in the affected heater shall be natural gas.

ii. The sulfur content of the natural gas fired in the affected heater shall not exceed 0.5 gr/100 scf.

c. Emissions from the affected heater shall not exceed the following limits (3-hr average):

Pollutant	Limit (lb/mmBtu)
NOx	0.011
CO	0.037
VOM	0.005
PM	0.0019
$PM_{10}/PM_{2.5}$	0.005
SAM	0.00021
CO_2e	117.0

2.3.3 Federal Emission Standards (NESHAP)

a. The affected heater is a "process heater," as defined by 40 CFR 63.7575, subject to the NESHAP for Institutional, Commercial, and Industrial Boilers and Process Heaters, 40 CFR Subpart DDDDD, and applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A. In particular, as the Permittee is the owner or operator of the affected heater, the following requirements apply.

i. The affected heater is subject to CFR 63.7540(a)(10), which provides that, pursuant to 40 CFR 63 Subpart DDDDD Table 3, Item 3, the Permittee must conduct a tune-up of the affected heater at least once per year to demonstrate continuous compliance as specified in 40 CFR 63.7540(a)(10)(i) through (vi), as applicable.

A. If the affected heater is not operating on the required date for a tune-up, the tune-up may be conducted within 30 days of startup, as provided by 40 CFR 63.7540(a)(13).

ii. The affected heater is subject to 40 CFR 63.7500(a)(3), which provides that, at all times, the Permittee must operate and maintain the affected heater, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Illinois EPA that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

2.3.4 State Emission Standards

a. The affected heater is subject to 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent into the atmosphere from the affected heater, except as provided in 35 IAC 212.123(b) and 35 IAC 212.124.

b. The affected heater is subject to 35 IAC 216.121, which provides that no person shall cause or allow the emission of CO into the atmosphere from any fuel combustion emission source with actual heat input greater than 2.9 MW (10 mmBtu/hr) to exceed 200 ppm, corrected to 50 percent excess air.

2.3.5 Nonapplicability Provisions

This permit is issued based on the affected heater not being subject to the NSPS for Small Industrial Commercial Institutional Steam Generating Units, 40 CFR 60 Subpart Dc. This is because the affected heater is a process heater and does not meet the definition of a steam generating unit provided in 40 CFR 63.11237.

2.3.6 Operational Requirements and Limits

a. The rated heat input capacity of the affected heater shall not exceed 17.59 mmBtu/hr.

2.3.7 Emission Limits

a. Emissions from the affected heater shall not exceed the following limits:

Pollutant	Hourly Limits (Pounds/Hour)	Annual Limits (Tons/Year)
NOx	0.19	0.85
CO	0.65	2.85
VOM	0.09	0.39
PM	0.09	0.39

$PM_{10}/PM_{2.5}$	0.09	0.39
SO_2	0.025	0.11
SAM	0.004	0.02
GHG (as CO_2e)	---	9,022

2.3.8 Testing Requirements

a. i. Within one year of initial startup of the affected heater or 120 days after achieving the maximum rate at which the affected heater will be operated, whichever comes first, the Permittee shall have performance tests conducted by an independent testing service on the affected heater.

A. These tests shall be conducted during maximum representative operating conditions (i.e., those conditions which reflect the highest emissions reasonably expected from the affected heater) to demonstrate compliance with the lb/mmBtu limits in Condition 2.3.2(b)(i) and the pounds/hour limits in Condition 2.3.7(a).

B. These tests shall be conducted in accordance with the testing requirements in Condition 3.1.

C. These tests shall be designed to measure the emissions of NOx, CO, VOM, PM, PM_{10} and $PM_{2.5}$ using the methods provided by Condition 3.1(a).

b. i. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with the requirements provided by Conditions 3.1(b) through (d).

ii. In addition to other information required in a test report, test reports shall include detailed information on the operating conditions of the affected heater during testing, including:

A. Fuel consumption (scf);

B. Firing rate (mmBtu/hr) and other significant operating parameters of the affected heater;

C. Opacity of the exhaust, 6-minute averages, as determined by USEPA Method 9, if visible emissions are normally present, as determined by USEPA Method 22.

2.3.9 Recordkeeping Requirements

a. For the affected heater, the Permittee shall maintain a file containing the following information with supporting documentation and calculations:

i. Heat input capacity, mmBtu/hr; and

ii. Maximum NOx, CO, PM, $PM_{10}/PM_{2.5}$, SO_2, SAM and GHG emission rates, lb/mmBtu and lb/hour.

b. The Permittee shall maintain records of the fuel usage for the affected heater (scf/month and scf/year).

c. The Permittee shall keep inspection, maintenance, and repair logs or other similar records for the affected heater that contain the information specified in Condition 3.4(b).

d. The Permittee shall maintain records of the emissions of NOx, CO, SO_2, SAM, VOM, GHG (as CO_2e), PM and $PM_{10}/PM_{2.5}$ from the affected heater (tons/month and tons/year), with supporting documentation and calculations.

e. NESHAP Records:

i. Pursuant to 40 CFR 63.7555(a), for the affected heater, the Permittee must keep records in accordance with 40 CFR 63.7555(a)(1) and (2).

ii. The Permittee shall keep records for the affected heater in accordance with the requirements of 40 CFR 63.7560.

2.3.10 <u>Reporting Requirements</u>

a. The Permittee shall notify the Illinois EPA of deviations or exceedances of the affected heater with the permit requirements in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

b. NESHAP Notification and Reporting Requirements:

i. Pursuant to 40 CFR 63.7545(a), the Permittee must submit to the Illinois EPA all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), 63.8(f)(4) and (6), and 63.9(b) through (h), as applicable, by the dates specified.

ii. Pursuant to 40 CFR 63.7574(c), as specified in 40 CFR 63.9(b)(4) and (5), the Permittee must submit an Initial Notification no later than 15 days after the actual date of startup of the source.

iii. Pursuant to 40 CFR 63.7550(a), the Permittee must submit each report of 40 CFR 63 Subpart DDDDD Table 9 that applies.

iv. Pursuant to 40 CFR 63.7550(b), the Permittee must submit each report, according to 40 CFR 63.7550(h), by the date in 40 CFR 63 Subpart DDDDD Table 9 and according to the requirements in 40 CFR 63.7550(b)(1) through (4), as applicable. For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 40 CFR 63.7540(a)(10) and not subject to emission limits or 40 CFR 63 Subpart DDDDD Table 4 operating limits, the Permittee may submit only an annual compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4), instead of a semi-annual compliance report.

A. Pursuant to 40 CFR 63.7550(h), the Permittee must submit the reports according to the procedures specified in 40 CFR 63.7550(h)(1) through (3), as applicable.

Subpart 2.4: Emergency Engines

2.4.1-1 Introduction

Three diesel-fired emergency engines would be installed to support the facility operations. Two identically sized engines would each power a corresponding electrical generator to provide power to critical equipment during power outages. A third engine would power the pump serving the fire water system. The fuel for the affected engines would be ultra-low sulfur diesel (ULSD).

2.4.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.4, the two engines each powering an electric generator (EP-5 and EP-6) are referred to as the "affected generator engines" and the engine serving the fire water system (EP-7) is referred to as the "affected fire pump engine." Collectively, the affected generator engines and affected fire pump engine are referred to as the "affected engines."

Emission Unit	Description	Control
Emergency Engine (EP-5)	4,332 hp diesel-fired engine for CT/HRSG operations. Base load of 3,232 kW	None
Emergency Engine (EP-6)	4,332 hp diesel-fired engine for CCS operation. Base load of 3,232 kW	None
Emergency Engine (EP-7)	422 hp diesel-fired engine used to support the Fire Water Pump. Base load of 315 kW	None

2.4.2 Control Technology Determination (BACT)

a. i. The affected generator engines shall be designed and operated to comply with the applicable limits of the NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII, for emergency engines other than fire pump engines as listed in Conditions 2.4.3-1(b)(i) and (d) of this permit. These applicable limits represent BACT for NOx, VOM, CO, PM and $PM_{10}/PM_{2.5}$.

ii. The affected fire pump engine shall be designed and operated to comply with the applicable limits of the NSPS, 40 CFR 60 Subpart IIII, for fire pump engines as listed in Conditions 2.4.3-1(b)(ii) and (d) of this permit. These applicable limits represent BACT for NOx, VOM, CO, PM and $PM_{10}/PM_{2.5}$.

b. The GHG emissions, as CO_2e, of the affected engines shall each not exceed 73.96 kg/mmBtu (hourly average).

c. The SAM emissions of the affected engines shall not exceed the following limits (hourly average):

i. For each affected generator engine: 0.0071 lb/hr, and

ii. For the affected fire pump engine: 0.0006 lb/hr.

d. The affected engines shall not exceed the operational limit in Condition 2.4.6(d) for maintenance checks and readiness testing of each engine.

e. The affected engines shall be operated and maintained in accordance with good combustion practices.

f. Ultra-low-sulfur diesel shall be the only fuel used in the affected engines.

2.4.3-1 Federal Emission Standards (NSPS)

a. The affected engines are subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII, and applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A.

b. i. The affected generator engines are subject to 40 CFR 60.4205(b), which provides that the Permittee must comply with the emission standards for new nonroad compression ignition (CI) engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI internal combustion engines (ICE). In particular, the affected generator engines are subject to the smoke standards in 40 CFR 1039.105 and the following emission standards in 40 CFR 1039, Appendix I:

Pollutant	Emission Standard (g/kW-hr)
NOx + NMHC	6.4
CO	3.5
PM	0.20

ii. The affected fire pump engine is subject to 40 CFR 60.4205(c), which provides that the Permittee must comply with the emission standards in Table 4 of 40 CFR 60 Subpart IIII, for all pollutants applicable to units with a maximum engine power greater than 175 hp but less than 750 hp, as follows.

Pollutant	Emission Standard (g/kW-hr)
NOx + NMHC	4.0
CO	3.5
PM	0.20

c. The affected engines are subject to 40 CFR 60.4206, which provides that the Permittee must operate and maintain the affected engines to achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engines.

d. The affected engines are subject to 40 CFR 60.4207(b), which provides that the Permittee must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel.

i. Pursuant to 40 CFR 1090.305, the diesel fuel must have a maximum sulfur content of 15 ppm and must have a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume.

2.4.3-2 Federal Emission Standards (NESHAP)

a. The affected engines are subject to the NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE), 40 CFR 63 Subpart ZZZZ.

i. The affected generator engines are subject only to the initial notification requirements of 40 CFR 63.6645(f). No further requirements for these engines apply under 40 CFR 60 Subpart ZZZZ. This is because, pursuant to 40 CFR 63.6590(b)(i), these engines are new emergency stationary RICEs with site ratings of more than 500 brake horsepower located at a major source of HAP emissions.

ii. For the affected fire pump engine, pursuant to 40 CFR 63.6590(c)(6), a new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions must meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII, for compression ignition engines.

2.4.4 State Emission Standards

a. The affected engines are subject to 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit, except as provided by 35 IAC 212.123(b) and 212.124.

b. The affected engines are subject to 35 IAC 214.301, which provides that the emission of SO_2 into the atmosphere from the affected engines shall not exceed 2,000 ppm.

c. The affected engines are subject to 35 IAC 214.305(a)(2), which provides that the sulfur content of all distillate fuel oil used by the affected engines must not exceed 15 ppm.

2.4.5 Nonapplicability Provisions

a. This permit is issued based on the affected engines not being subject to the requirements of 35 IAC Part 212 Subpart L, because a process weight rule cannot be set due to the nature of such unit, so that these rules cannot be reasonably applied, pursuant to 35 IAC 212.323.

b. This permit is issued based on the affected engines not being subject to the state emission standards in 35 IAC Part 217 Subpart Q for NOx emissions from Stationary Reciprocating Internal Combustion Engines and Turbines. This is because each affected engine would be used as an “emergency or stand-by unit,” as defined at 35 IAC 211.1920, and pursuant to 35 IAC 217.386(c)(1), emergency units are not subject to these emission standards. However, pursuant to 35 IAC 217.386(c)(1), the Permittee must still comply with the recordkeeping requirement under 35 IAC 217.396(a)(13).

2.4.6 Operational Requirements and Limits

a. The affected engines are subject to 40 CFR 60.4211(a), which provides that, except as provided under 40 CFR 60.4211(g), the Permittee shall operate and maintain the affected engines according to the manufacturer’s emission related written instructions. In addition, the Permittee may only change those emission-related settings that are permitted by the manufacturer. The Permittee shall also meet the requirements of 40 CFR 1068, as applicable.

b. The affected engines are subject to 40 CFR 60.4211(c), which provides that the engines must be installed and configured according to the manufacturer’s specifications.

i. For each affected generator engine, the Permittee shall comply by purchasing engines certified to the emission standard in 40 CFR 60.4205(b) for the same model year and maximum engine power.

ii. For the affected fire pump engine, the Permittee shall comply by purchasing an engine certified to the emission standard in 40 CFR 60.4205(c) for the same model year and National Fire Protection Association (NFPA) nameplate engine power.

c. The affected engines are subject to 40 CFR 60.4211(f), which provides that for each affected engine to be considered emergency stationary ICE under 40 CFR 60 Subpart IIII, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year is prohibited. If the Permittee does not operate the engine according to these requirements the engine will not be considered an emergency engine under 40 CFR 60 Subpart IIII and must meet all requirements for non-emergency engines.

i. The Permittee may operate the affected engine for any combination of the purposes specified in 40 CFR 60.4211(f)(2) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations counts as part of the 100 hours per calendar year allowed by this condition.

A. The affected engines may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engines. The Permittee may petition the Illinois EPA or USEPA for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

ii. Each affected engine may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are to be counted as part of the 100 hours per calendar year for maintenance and testing provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to otherwise supply power as part of a financial arrangement with another entity, except as provided below:

A. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

1. The affected engine is dispatched by the local balancing authority or local transmission and distribution system operator;

2. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

3. The dispatch follows reliability, emergency operation, or similar protocols that follow specific North American Electric Reliability Corporation (NERC), regional, state, public utility commission or local standards or guidelines.

4. The power is provided only to the facility itself or to support the local transmission and distribution system.

5. The Permittee identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the Permittee.

d. The operating hours of each affected engine shall not exceed 100 hours/year. Except as otherwise specified by an applicable requirement (e.g., the NSPS operating hour requirements), compliance with this annual limit shall be determined from a running total of 12 months of data.

e. The rated capacities of the affected engines shall not exceed the following limits:

i. Each affected generator engine: 3,232 kW.

ii. Affected fire pump engine: 315 kW.

2.4.7 Emission Limits

a. i. A. Emissions of SO_2 and total HAP from each affected generator engine shall not exceed 0.046 lb/hr and 0.04 lb/hr, respectively.

B. Annual emissions from each affected generator engine shall not exceed the following limits:

Pollutant	Limits (Tons/Year)
NOx	2.17
CO	1.25
$PM/PM_{10}/PM_{2.5}$	0.07
VOM	0.11
SO_2	0.0023
SAM	0.0004
Total HAP	0.002
GHG, as CO_2e	225.84

ii. A. Emissions of SO_2 and total HAP from the affected fire pump engine shall not exceed 0.004 lb/hr and 0.01 lb/hr, respectively.

B. Annual emissions from the affected fire pump engine shall not exceed the following limits:

Pollutant	Limits (Tons/Year)
NOx	0.14
CO	0.12
$PM/PM_{10}/PM_{2.5}$	0.01
VOM	0.14
SO_2	0.0002
SAM	0.00003
Total HAP	0.0005
GHG, as CO_2e	19.49

2.4.8 Monitoring Requirements

Pursuant to 40 CFR 60.4209(a), as the affected engines do not meet the standards applicable to non-emergency engines, the Permittee must install a non-resettable hour meter on the affected engines prior to startup of the affected engines.

2.4.9 Recordkeeping Requirements

a. The Permittee shall comply with the applicable recordkeeping requirements of the NSPS.

b. Pursuant to 35 IAC 214.305(a)(3), the owner or operator must:

i. Maintain records demonstrating that the fuel oil used by the affected engines complies with the requirements in 35 IAC 214.305(a)(2), such as records from the fuel supplier indicating the sulfur content of the fuel oil; and

ii. Retain the records for at least 5 years, and provide copies of the records to the Illinois EPA within 30 days after receipt of a request by the Illinois EPA.

c. Pursuant to 35 IAC 217.386(c)(1), the Permittee shall keep records documenting the annual hours of operation of the affected engines in non-emergency situations.

d. The Permittee shall maintain records of the following items for the affected engines:

i. The set runtime for the affected engines (hours/month and hours/year).

ii. An operating log or other records that, at a minimum, includes:

A. Information for each startup of the affected engines;

B. Information for each time that fuel is burned, including date, duration, and the amount of fuel burned; and

C. Confirmation that the affected engines are only used as an emergency or standby unit.

iii. An inspection, maintenance, and repair log for the engines that, at a minimum, lists each activity performed with date.

iv. A. Emissions of NOx, CO, VOM, $PM/PM_{10}/PM_{2.5}$, SO_2, SAM, total HAPs, and GHGs (expressed as CO_2e) from the affected generator engines, combined, and for the affected fire pump engines, with supporting calculations (tons/month and tons/year).

B. A file that contains the emission factors used by the Permittee to determine emissions from the affected engines, with supporting documentation.

C. The maximum emission rate for NOx, CO, VOM, PM/PM_{10}/$PM_{2.5}$, SO_2, SAM, total HAPs from each affected engine in pounds/hour.

v. The type of fuel used in the affected engines, including maximum sulfur content.

2.4.10 Reporting Requirements

a. For the affected engines, the Permittee shall comply with the applicable notification and reporting requirements of the Engine NSPS, including 40 CFR 60.4214(d).

b. The Permittee shall notify the Illinois EPA within 30 days after discovery of deviation from the requirements of 35 IAC 214.305(a). At minimum, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken, pursuant to 35 IAC 214.305(a)(3)(C).

c. If there is any deviation or exceedance from the requirements for the affected engines, other than those related to 35 IAC 214.305(a), the Permittee shall submit a report to the Illinois EPA in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

Subpart 2.5: Piping and Piping Equipment

2.5.1-1 Introduction

Piping and piping equipment, such as valves, pumps and flanges would be installed to transport the following materials: (i) natural gas for the CTG/HRSG and dewpoint heater (Subparts 2.1 and 2.3 respectively); (ii) solvents to the absorber column in the CCP (Subpart 2.1); (iii) diesel to the emergency engines (Subpart 2.4); and (iv) CO_2 in the pipeline going from the CCP to the facility boundary.

Piping and piping equipment in natural gas, diesel, solvent and CO_2 service would have the potential to leak. Pipeline quality natural gas consists primarily of methane (CH_4) (a GHG), while also containing hydrocarbons and CO_2 (a GHG) in smaller quantities. Leaks from the piping and piping equipment in natural gas service would cause the emission of GHGs and VOM. Leaks from the piping and piping equipment handling diesel and solvent would have the potential to emit VOM. The pipeline from the CCP would be a pure stream of CO_2; subsequently, leaks from this pipeline would consist only of GHGs. Emissions of GHG and VOM from piping and piping equipment would be addressed through timely identification and repair of any leaks that occur, i.e., a Leak Detection and Repair (LDAR) program, or by use of "leakless" equipment. Because the vast majority of the GHG emissions from piping and piping equipment comes from methane (as opposed to CO_2), the LDAR program requirements focus on methane. Total CO_2 emissions projected for piping and piping equipment would be at most 10 pounds per year.

2.5.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.5, piping and piping equipment identified in Condition 2.5.1-1 and listed below are referred to as "affected equipment."

Emission Unit/ Operation	Description	Control
Natural Gas Fugitives (EP-8) ULSD Fugitives (EP-10A and EP-10B) Solvent Fugitives (EP-11) CO_2 Pipeline Fugitives (EP-28)	Piping and piping equipment serving plant operations, transporting natural gas, solvents, ultra-low sulfur diesel, and CO_2.	LDAR Program Leakless equipment High quality components

2.5.2 Control Technology Determination (BACT)

a. The Permittee shall install and operate "leakless" valves and pumps, to the extent that "leakless" valves and pumps are available and technically feasible. If "leakless" valves and pumps are not available or technically feasible, use of high-quality equipment that is designed for the specific service in which it is employed, shall be installed and operated.

b. The Permittee shall implement a non-instrumental LDAR program, including the completion of auditory, visual and olfactory (AVO) inspections on a monthly basis to identify any equipment that is leaking VOM, methane or CO_2.

c. The Permittee shall implement an instrument-based LDAR program that meets requirements of the NSPS for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60 Subpart VVb, including relevant portions of the NSPS for work practices, testing, recordkeeping and reporting. In particular, the Permittee must:

   i. Monitor all affected equipment in accordance with 40 CFR 60.482-1b through 60.482-11b, with the following exceptions:

      A. The Permittee must use an optical gas imaging instrument as an alternative to inspecting leaks in accordance with USEPA Method 21, unless the Permittee demonstrates to the Illinois EPA that optical gas imaging would not be equally or more effective in the identification of leaks than USEPA Method 21; and

      B. For all affected equipment, a leak is defined as any visible emissions from affected equipment observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater of methane or VOM using Method 21 of 40 CFR 60 Appendix A-7.

   ii. Meet the requirements for optical gas imaging in 40 CFR 60.18(g), (h) and (i), including the requirement to conduct inspections for leaks in accordance with USEPA Method 21 at least once per year;

   iii. Keep records identified in 40 CFR 60.486b; and

   iv. Submit reports identified in 40 CFR 60.487b.

d. Emissions from the affected equipment shall not exceed the following limits:

   i. GHG: 60.93 tons/year.

   ii. VOM: 4.86 tons/year.

2.5.3 <u>Nonapplicability Provisions</u>

a. This permit is issued based on the affected equipment not being subject to the requirements of the NSPS, 40 CFR 60 Subpart VVb. This is because they are not located at a synthetic chemical manufacturing facility for purposes of this NSPS because they do not produce as an intermediate or final product any chemical listed in 40 CFR 60.489b. Note, however, the facility must meet requirements of this NSPS as a requirement of BACT (See Condition 2.5.2(c)).

b. This permit is issued based on the affected equipment, such as pumps and compressors, not being subject to the control requirement of 35 IAC 215.142 because none of this equipment would handle a volatile organic liquid with a vapor pressure of 2.5 psia or greater at 70°F.

2.5.4 <u>Recordkeeping Requirements</u>

a. The Permittee shall maintain a log of each instance where high-quality equipment was installed rather than leakless equipment. This documentation shall be retained until the particular equipment is no longer present at the source, and shall include the following information:

i. A description of the technical specifications for the particular equipment, including information for: equipment type; equipment service and operating conditions, e.g., liquid temperature and pressure; service life of equipment or packing; manner of valve operation, e.g., manual or automatic; and speed of valve operation.

ii. A list of select equipment manufacturers that make products that generally satisfy the technical specifications, quality standards, and safety standards established for equipment to be installed at the facility.

iii. The manufacturers or vendors contacted for the availability of the leakless equipment and a copy of their response.

iv. An explanation of why leakless equipment was not installed if it was available and technically feasible.

b. In addition to the records required by Condition 2.5.2(c)(iii), the Permittee shall also maintain a log or other records for each monthly non-instrumental inspection, including:

i. Name of person performing the inspection;

ii. Equipment identification;

iii. Date of inspection;

iv. Observations made during the inspection; and

v. Any corrective actions taken as a result of the inspection.

c. For affected equipment, the Permittee shall maintain a log or other records that identify leaking equipment and a compilation of leaking equipment by month by type of equipment, the nature of the leaks, and the duration of the leaks.

d. For affected equipment, the Permittee shall maintain the following records related to emissions of GHGs (as CO_2e) and VOM:

i. A file containing the equipment count by type and service, and emission factors used by the Permittee to determine the emissions from leaks in different types of equipment, with supporting documentation and calculations. These calculations shall be updated, as appropriate, following completion of construction or upon subsequent changes to the piping systems at the facility.

ii. Records of the emissions of GHGs (as CO_2e) and VOM (tons/month and tons/year), with supporting data and calculations.

2.5.5 <u>Reporting Requirements</u>

a. i. For the affected equipment, the Permittee shall notify the Illinois EPA of deviations from the requirements of this permit for this equipment, in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

ii. Deviations from requirements that must be reported in reports pursuant to the NSPS, as required by Condition 2.5.2(c)(iv), shall be reported in such reports.

Subpart 2.6: Roadways and Parking Areas

2.6.1-1 Introduction

Fugitive dust (particulate emissions) would be generated by vehicle traffic on roadways and parking areas at the facility. The cogeneration facility would be serviced by six total roadways ranging in lengths from a fifth of a mile to a half mile for and periodic delivery of process chemicals and removal of spent chemical waste products to be sent off-site. Emissions of particulates (PM, PM_{10}, and $PM_{2.5}$) would be controlled by paving all roadways, which would handle all the traffic coming into or leaving the facility, and implementation of dust control measures, including sweeping, and application of dust suppressing materials, if necessary.

2.6.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.6, roadways and parking areas identified in Condition 2.6.1-1 and listed below are referred to as "affected roadways and parking areas."

Emission Unit/ Operation	Description	Control
HR-1 (Ammonia) HR-2 (Diesel) HR-3 (CCP) HR-4 (Warehouse) HR-5 (Cooling Tower) HR-6 (Turbine)	Roadways serving plant operations, including material deliveries (ammonia and diesel), CCP, warehouse, cooling tower, and CT/HRSG	Paved Haul Roads Water Spray Suppression Sweeping

2.6.2 Control Technology Determination (BACT)

a. The opacity of fugitive particulate matter emissions from affected roadways and parking areas shall not exceed 10 percent. For this purpose, opacity shall be determined in accordance with 35 IAC 212.109.

b. All affected roadways and parking areas shall be paved.

c. The Permittee shall implement a Fugitive Dust Control Program that includes the following to comply with the limits in Condition 2.6.2(a):

i. Vacuum sweeping with wet suppression at least once every 14 days, except when:

A. It is raining or snowing at the time of the scheduled treatment;

B. The affected roadway or parking area is covered by ice or snow or remains wet from recent precipitation or the previous wet suppression; or

C. The affected roadway or parking area is not being used on that day.

ii. Prompt cleanup of spillage onto affected roadways and parking areas.

iii. A speed limit of 15 mph shall be posted for all affected roadways and parking areas.

2.6.3 State Emission Standards

The affected roadways and parking areas are subject to 35 IAC 212.301 and 212.314, which provides that the Permittee shall not cause or allow the emission of fugitive particulate matter from any process, including material handling and storage activities, when looking generally toward the zenith at a point beyond the property line of the source, except when the wind speed is greater than 25 miles per hour.

2.6.4 Nonapplicability Provisions

This permit is issued based on the affected roadways and parking areas not being subject to the requirements of 35 IAC 212.321. This is because, due to the disperse nature of these units, this regulation cannot be reasonably applied.

2.6.5 Emission Limits

Emissions of PM, PM_{10}, and $PM_{2.5}$ from the affected roadways and parking areas shall not exceed 0.12, 0.02, and 0.01 tons/year, respectively. Compliance with these limits shall be determined from the amount and nature of vehicle traffic associated with the operation of the cogeneration facility, specific operating information for affected roadways and parking areas, and appropriate emission factors.

2.6.6 Opacity Observations

a. The Permittee shall conduct opacity observations of fugitive emissions, if any, from the affected roadways and parking areas to demonstrate compliance with Condition 2.6.2(a).

b. Opacity observations shall be conducted as follows. For these observations, the Permittee shall submit test plans, test notifications, and test reports, as specified by Condition 3.2.

  i. Observations shall first be completed no later than 30 days after the startup of the cogeneration facility.

  ii. Observations shall be repeated within 10 days in the event of changes involving affected roadways or parking areas that would act to increase opacity, e.g., changes in the amount or type of traffic on affected roadways and parking areas; and changes in the standard operating practices for affected roadways and parking areas, such as application of salt or traction material during cold weather.

2.6.7 Visible Emissions Observations

a. The Permittee shall perform visible emissions observations of fugitive emissions from the affected roadways and parking areas to demonstrate compliance with Condition 2.6.3.

  i. The initial observation shall be performed in conjunction with the opacity observation required by Condition 2.6.6(b)(i).

  ii. Subsequent observations shall be performed within 12 months of the prior observation.

  iii. The duration of observations shall be at least 6 minutes.

  iv. Observations shall be conducted in accordance with USEPA Method 22.

b. The Permittee shall maintain logs for determinations of visible emissions that include the following information:

i. Date and time of observation(s).

ii. Name and employer of observer.

iii. Description of observation condition, including recent weather.

iv. Description of the operating conditions of the operation or unit observed.

v. Determinations of the presence of visible emissions.

2.6.8 Recordkeeping Requirements

a. The Permittee shall keep a file containing:

i. The emission factors used to determine the PM, PM_{10}, and $PM_{2.5}$ emissions from the affected roadways and parking areas, with supporting documentation.

ii. The maximum PM, PM_{10}, and $PM_{2.5}$ emissions of the affected roadways and parking areas, in tons/year, considering the maximum amounts of vehicle traffic needed for the operation of the plant, with supporting calculations and documentation.

b. The Permittee shall maintain records of the following:

i. Records for each treatment of the affected roadways and parking areas:

A. The date, time, and the identification of the truck(s) or treatment equipment used;

B. Dust suppressant target application rate and the identity of dust suppressant applied;

C. Identity of equipment used and identification of any deficiencies in the condition of equipment.

ii. Records for each incident when control measures were not implemented, e.g., precipitation, and for each incident when additional control measures were implemented due to particular activities, including description, date, a statement of explanation, and expected duration of such circumstances.

c. The Permittee shall maintain records of the PM, PM_{10}, and $PM_{2.5}$ emissions (tons/month and tons/year) of the affected roadways and parking areas, based on the data for activities at the cogeneration plant, the above records for the affected roadways and parking areas including data for implementation of the Fugitive Dust Control Program, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

2.6.9 Reporting Requirements

For the affected roadways and parking areas, the Permittee shall promptly notify the Illinois EPA of exceedances or deviations from the requirements of this permit for the affected roadways and parking areas in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

Subpart 2.7: Circuit Breakers

2.7.1-1 Introduction

The electrical switchgear at the cogeneration facility would include circuit breakers that would use gaseous sulfur hexafluoride (SF_6) as a dielectric or insulating material. Although the circuit breakers would be pressurized without any vents directly to the atmosphere, leaks of SF_6, which is a GHG, may occur.

2.7.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.7, circuit breakers identified in Condition 2.7.1-1 and listed below are referred to as "affected circuit breakers."

Emission Unit/ Operation	Description	Control
Circuit Breakers	Circuit breakers that use SF_6 as an insulating material	LDAR Program

2.7.2 Control Technology Determination (BACT)

a. The affected circuit breakers shall be low leak rate design circuit breakers, guaranteed by the manufacturer to have an SF_6 leak rate of no more than 0.5 percent on a 12-month rolling basis.

b. The Permittee shall implement a Leak Detection and Repair (LDAR) program meeting the requirements of Condition 2.7.3, including an alarm to identify leaks.

c. The Permittee shall implement systematic operations tracking that provides for management of cylinders containing SF_6 and the recycling of carts.

d. The total emissions of SF_6 from the affected circuit breakers shall not exceed 2.0 pounds per year, on a 12-month rolling basis.

2.7.3 Leak Detection and Repair Program

a. i. The Permittee shall install, operate, and maintain a leak detection system on each affected circuit breaker, which system shall indicate the level of SF_6 or dielectric material in the unit (e.g., pressure of the material in the unit) and provide an alarm in the event that the level of material in the affected circuit breakers falls below the set point or level recommended by the manufacturer of the circuit breaker.

ii. The Permittee shall promptly respond to any alarm from the leak detection system on an affected circuit breaker required by Condition 2.7.2(b), expeditiously investigating the cause for the alarm and implementing any appropriate corrective action based on the investigation to either reduce loss of SF_6 from the unit (e.g., repairing a leak or making changes to operating practices for the unit) or repairs to the leak detection system.

iii. If a leak is detected from an affected circuit breaker, as monitored in accordance with the LDAR Program required by Condition 2.7.2(b), the Permittee shall perform all action(s) necessary to eliminate the leak as soon as practicable but no later than 21 days following the leak; however, if the leak cannot be repaired within 21 days without the shutdown of the cogeneration facility, the leak shall be repaired during the next planned shutdown of the cogeneration facility.

b. The Permittee shall keep the following records for each leak detection system on an affected circuit breaker:

i. The data measured by the system recorded on at least a quarterly basis.

ii. Information for each alarm from the system, including date, time and action taken to resolve the alarm.

iii. Operational records and maintenance and repair records for the system.

iv. The operating and maintenance procedure(s) for the system recommended by the manufacturer.

2.7.4 Recordkeeping Requirements

a. The Permittee shall keep a file or other records containing the following information for the affected circuit breakers:

i. A listing of the circuit breakers, with the manufacturer and model number of each circuit breaker and its SF_6 content when fully charged.

ii. A copy of the manufacturer's guarantee for the design leak rate of SF_6 from each circuit breaker, percent loss on an annual basis.

iii. The recommended operating and maintenance procedure(s) for each circuit breaker as related to the use of SF_6 recommended by the manufacturer of the circuit breaker.

b. i. The Permittee shall maintain records for the addition of SF_6 to each affected circuit breaker following initially being filled or charged with SF_6, with date, the amount of SF_6 added (in hundredths of pounds), and explanation for loss, if known, and any other corrective actions taken.

ii. The Permittee shall maintain the following records for the overall addition of SF_6 to the affected circuit breakers, in hundredths of pounds, based on inventory data for SF_6:

A. The amount of SF_6 used in initially charging the affected circuit breakers (pounds).

B. The subsequent addition of SF_6 to the affected circuit breakers following initial charging of the units (pounds/month).

c. i. The Permittee shall maintain records of the annual leak rate from each affected circuit breaker, calculated as the total amount of SF_6 added to the circuit breaker in rolling 12-month period, as recorded pursuant to Condition 2.7.4(b)(i), and the amount of SF_6 in the unit when fully charged, as recorded pursuant to Condition 2.7.4(a)(i).

ii. The Permittee shall maintain records for the total emissions of SF_6 from the affected circuit breaker (pounds/month and pounds/year), as determined from the records required by Condition 2.7.4(b)(ii)(B), with supporting calculations.

2.7.5 Reporting

For the affected circuit breakers, the Permittee shall promptly notify the Illinois EPA of exceedances or deviations from the requirements of this permit for the affected circuit breakers in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

Subpart 2.8: Lube Oil System

2.8.1-1 Introduction

The new combustion turbine will be equipped with a dedicated lubrication system. Lubrication oil will be circulated through the turbine's machinery from the systems' oil sumps. The oil sumps will be equipped with a vent that will be controlled by an oil mist eliminator. Emissions from the oil mist eliminators are based on lube oil replacement rates for similar units equipped with mist eliminators. Both VOM and particulates are expected to be emitted from for the combustion turbine lube oil vent.

2.8.1-2 List of Emission Units and Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.8, the Lube Oil System identified in Condition 2.8.1-1 and listed below are referred to as "affected lube oil system."

Emission Unit/ Operation	Description	Control
Lube Oil System (EP-12)	Oil sumps vent will be equipped with a vent that will be controlled by an oil mist eliminator	Mist Eliminator

2.8.2 Control Technology Determination (BACT)

a. Emissions of VOM, PM and $PM_{10}/PM_{2.5}$ from the affected lube oil system shall be controlled by a mist eliminator.

b. i. Emissions of VOM from the affected lube oil system shall not exceed 0.01 tons/year.

ii. Emissions of PM and $PM_{10}/PM_{2.5}$ from the affected lube oil system shall not exceed 0.01 tons/year, each pollutant.

2.8.3 State Emission Standards

a. The affected lube oil system is subject to 35 IAC 215.301, which provides that no person shall cause or allow the discharge of more than 3.6 kg/hr (8 lbs/hr) of organic material into the atmosphere from any emission source, except as provided in 35 IAC 215.302, 215.303, 215.304 and the following exception: If no odor nuisance exists this limit shall apply only to photochemically reactive material.

b. The affected lube oil system is subject to 35 IAC 212.123, which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit, except as provided by 35 IAC 212.123(b) and 35 IAC 212.124.

2.8.4 Recordkeeping Requirements

a. For the affected lube oil system, the Permittee shall maintain a file or other records containing the maximum VOM, PM and $PM_{10}/PM_{2.5}$ emission rates in pounds/hour, with supporting documentation and calculations.

b. The Permittee shall maintain records of lube oil consumption rate of the oil recirculation system (gallons/month and gallons/year).

c. The Permittee shall maintain records of VOM, PM and $PM_{10}/PM_{2.5}$ emissions (tons/month and tons/year).

2.8.5 Reporting Requirements

For the affected lube oil system, the Permittee shall promptly notify the Illinois EPA of exceedances or deviations from the requirements of this permit for the affected lube oil system in accordance with Condition 3.6. These notifications shall include the information specified in Condition 3.5.

Part 3: General Permit Conditions

3.1 Emission Testing Requirements

a. The following USEPA Methods and procedures shall be used for testing, unless another USEPA method is approved by the Illinois EPA as part of its review of the test plan required by Condition 3.1(b):

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
PM (filterable)	USEPA Method 5
$PM_{10}/PM_{2.5}$ (filterable)	USEPA Method 201A[a]
Condensable Particulate Matter	USEPA Method 202[b]
Nitrogen Oxides (NOx)	USEPA Method 7 or 7E
Sulfuric Acid Mist	USEPA Method 8
Opacity	USEPA Method 9
Carbon Monoxide (CO)	USEPA Method 10
VOM and HAPs	USEPA Method 18 or 320 and 25 or 25A
Visible Emissions	USEPA Method 22
N_2O and CH_4	USEPA Method 320

Table Notes:

a. Method 5 may be used in lieu of 201A if all filterable particulate matter is assumed to be $PM_{10}/PM_{2.5}$. Notwithstanding other conditions of this permit, testing for filterable PM_{10} and $PM_{2.5}$ is not required if the stack conditions are such that Method 201A is not applicable, e.g., the presence of water droplets in the exhaust. In such case, filterable emissions of PM_{10} and $PM_{2.5}$ shall be determined from the measured PM emissions using appropriate published data from the portion of the filterable PM emissions that are PM_{10} and $PM_{2.5}$. For this purpose, Methods 5 and 202 or 201 may be used in lieu of Method 201A for determining emissions of PM_{10} and $PM_{2.5}$.

b. If the gas stack and filtration temperature never exceed 30 °C (85 °F) during the stack test, then use of USEPA Method 202 is not required.

b. The Permittee shall submit a written test plan to the Illinois EPA for testing and if a significant change in the procedures for this testing is planned from the procedures followed in the previous test. This plan shall be submitted at least 60 days prior to the actual date of testing, unless a shorter period is approved by the Illinois EPA. This test plan must include the following information as a minimum:

i. A description of the planned test procedures.

ii. The person(s) who will be performing sampling and analysis and their experience with similar tests.

iii. The specific conditions under which testing will be performed, including a discussion of why these conditions would be considered maximum operating conditions and the means or manner by which the operating parameters for the emission unit and any control equipment will be determined.

iv. The specific determinations of emissions and operation that are intended to be made, including sampling and monitoring locations.

v. The test method(s) that will be used, with the specific analysis method, if the method can be used with different analysis methods.

c. The Permittee shall notify the Illinois EPA prior to conducting these measurements to enable the Illinois EPA to observe testing. Notification for the expected date of testing shall be submitted a minimum of 30 days prior to the expected date. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days prior to the actual date of the test. The Illinois EPA may accept shorter advance notice if it does not interfere with the Illinois EPA's ability to observe testing.

d. Copies of the Final Reports for emission tests shall be forwarded to the Illinois EPA within 30 days after the test results are compiled and finalized but no later than 60 days after the date of testing. At a minimum, the Final Report for testing shall contain the following. Copies of emission test reports shall be retained for at least five years after the date that an emission test is superseded by a more recent test.

i. General information, i.e., date of test, names of testing personnel, and names of Illinois EPA observers.

ii. A summary of results.

iii. A detailed description of operating conditions of the emission unit(s) during testing, including:

A. Process information, i.e., mode(s) of operation and process rate.

B. Control equipment information, i.e., equipment condition and operating parameters during testing.

iv. Description of test method(s), including description of sampling points, sampling train, analysis equipment, and test schedule.

v. Data and calculations, including copies of all raw data sheets and records of laboratory analyses, sample calculations, and data on equipment calibration.

vi. Conclusions.

e. The Permittee shall retain copies of emission test reports for at least three years beyond the date that an emission test is superseded by a more recent test

3.2 Visual Determinations of Opacity

a. Opacity of emissions shall be determined during representative weather and operating conditions by a qualified observer in accordance with USEPA Method 9, as further specified below.

b. The duration of opacity observations for each test shall be at least 18 minutes (three 6-minute averages) unless the average opacities for the first 12 minutes of observations (two six-minute averages) are both no more than half of the most stringent requirement applying to opacity.

c. i. The Permittee shall notify the Illinois EPA prior to conducting opacity observations required by this permit to enable the Illinois EPA to witness these observations.

Notification for the expected date of observations shall be submitted a minimum of 30 days prior to the expected date and identify the units for which observations for opacity will be performed. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days prior to the actual date of testing. The Illinois EPA may accept shorter advance notice if it does not interfere with the Illinois EPA's ability to observe testing.

ii. This notification shall also identify the party(ies) that will be performing opacity observations and the set or sets of operating conditions under which observations will be made.

iii. The Permittee shall promptly notify the Illinois EPA of any changes in the time or date for opacity observations.

d. The Permittee shall provide a copy of its observer's readings to the Illinois EPA at the time of testing, if Illinois EPA personnel are present.

e. Copies of the Final Reports for opacity observations shall be forwarded to the Illinois EPA within 30 days after the test results are compiled and finalized but no later than 60 days after the date of testing. At a minimum, the Final Report for testing shall contain the following. Copies of emission opacity observation reports shall be retained for at least five years after the date that an emission test is superseded by a more recent test:

i. Date and time of testing.

ii. Name and employer of qualified observer, with a copy of his or her current certification.

iii. Description of observation condition, including recent weather.

iv. Description of the operating conditions of the affected operation or unit.

v. Opacity determinations, accompanied by raw data.

vi. Conclusions.

f. The Permittee shall retain copies of emission test reports for at least three years beyond the date that an emission test is superseded by a more recent test

3.3 Operation and Maintenance Procedures

a. Where this permit requires the Permittee to operate or maintain emission units in accordance with written procedures, such procedures may incorporate procedures provided by the equipment manufacturer or supplier if a copy of these procedures is attached to the Permittee's procedures.

b. For continuous monitoring devices and operational instrumentation required by this Permit, the Permittee shall maintain a copy of manufacturer's or supplier's recommended operating and maintenance procedures and its specifications for the performance of the devices.

3.4 General Requirements for Logs

a. Operating logs or other similar records required by this permit shall, at a minimum, include the following information related to emissions units and their associated control devices associated with this project:

i. Information identifying periods when an emissions unit or group of related emissions units was not in service.

ii. For periods when a unit or group of related units is in service and operating normally, relevant process and control system information to generally confirm normal operation.

iii. For periods when a unit or group of related units is in service and is not operating normally, identification of each such period, with detailed information describing the operation of the unit(s), the potential consequences for additional emissions from the unit(s), the potential of any excess emissions from the affected unit(s), the actions taken to restore normal operation, and any actions taken to prevent similar events in the future.

iv. Other information as may be appropriate to show that the emissions unit or group of related emissions units is operated in accordance with good air pollution control practice.

b. Inspection, maintenance and repair logs or other similar information required by this permit shall, at a minimum, include the following information related to emissions units and their associated control system(s) associated with this project:

i. Identification of equipment, with date, time, responsible employee and type of activity.

ii. For inspections, a description of the inspection, findings, and any recommended actions, with reason.

iii. For maintenance and repair activity, a description of actions taken, reason for action (e.g., preventative measure or corrective action as a result of inspection), probable cause for requiring maintenance or repair if not routine or preventative, and the condition of equipment following completion of the activity.

iv. Other information as may be appropriate to show that the emissions unit or group of related emissions units is maintained in accordance with good air pollution control practices, including prompt repair of defects that interfere with effective control of emissions.

c. The logs required by this permit may be kept in manual or electronic form and may be part of a larger information database maintained by the Permittee provided that the information required to be kept in a log is readily accessible.

3.5 <u>General Requirements for Recordkeeping for Deviations and Exceedances</u>

Except as specified in a particular provision of this permit, records for deviations and exceedances from applicable requirements shall include at least the following information: the date, time and estimated duration of the deviation and exceedance; a description of the deviation and exceedance; the manner in which the deviation and exceedance was identified, if not readily apparent; the probable cause for deviation and exceedance, if known, including a description of any equipment malfunction or breakdown associated with the deviation and exceedance; information on the magnitude of the deviation and exceedance, including actual emissions or performance in terms of the applicable standard if measured or readily estimated; confirmation that standard procedures were followed or a description of any event-specific corrective actions taken; and a description of any preventative measures taken to prevent future occurrences, if appropriate.

3.6 Reporting of Deviations and Exceedance

a. Reports of deviations and exceedances shall include the following information:

i. Identification of the deviation and exceedance, with date, time, duration and description.

ii. Description of the effect of the deviation and exceedance on compliance, with an estimate of the excess emissions that accompanied the deviation and exceedance, if any.

iii. Description of the probable cause of the deviation and exceedance and any corrective actions or preventive measures taken.

Attachment 1: Summary of the Potential Emissions of the Cogeneration Facility (Tons/Year)

Operation	NOx	CO	VOM	PM	PM_{10}	$PM_{2.5}$	SO_2	SAM	GHG (as CO_2e)	Total HAP
Cogeneration Unit[a]	218.39	238.98	107.32	89.51	162.09	162.09	33.61	30.87	2,982,650	13.57
Carbon Capture Process	-	-	542.80	-	-	-	-	-		300.66
Cooling Tower System	-	-	-	5.05	2.69	0.01	-	-	-	-
Dewpoint Heater	0.85	2.85	0.39	0.39	0.39	0.39	0.11	0.02	9,022	0.14
Emergency Engines[b]	4.48	2.62	0.36	0.15	0.15	0.15	0.0042	0.00083	471.17	0.01
Piping and Piping Equipment[c]	-	-	4.86	-	-	-	-	-	60.93	-
Roadways and Parking Areas	-	-	-	0.12	0.02	0.01	-	-	-	-
Tanks[d]	-	-	0.07	-	-	-	-	-	-	-
Circuit Breaker	-	-	-	-	-	-	-	-	23.5	-
Lube Oil System	-	-	0.01	0.01	0.01	0.01	-	-	-	-
Totals[e]:	223.72	244.45	655.81	95.23	165.35	162.66	33.72	30.89	2,992,228	314.38

Table Notes:

a. This summary addresses operation of the facility after initial shakedown of the cogeneration facility, as defined in Condition 1.13, is complete.
b. Emergency engines include the two emergency generators (EP-5 and EP-6) and the firewater pump engine (EP-7).
c. Includes fugitive emissions from piping and piping equipment in diesel (EP-10A & EP-10B), natural gas (EP-8), monoethanolamine (EP-11), and CO_2 (EP-28) service.
d. Tanks include fixed-roof storage tanks for organic liquids (diesel and ethanolamine).
e. Totals may not match sum of permitted emissions totals due to rounding.

Attachment 2: Acid Rain Permit

217/785-1705

ACID RAIN PROGRAM
PHASE II PERMIT

Broadwing Energy Center
Attn: Jonathan Wiens, CEO
750 Town and Country Boulevard, Suite 660
Houston, TX 77042

ORIS No.:	[To be assigned by ORIS]
IEPA I.D. No.:	115015BWL
Source/Unit:	Broadwing Energy Center/Cogeneration Unit 1
Date Received:	April 4, 2025
Date Issued:	
Effective Date:	
Expiration Date:	

STATEMENT OF BASIS:

In accordance with Section 39.5(17)(b) of the Illinois Environmental Protection Act and Titles IV and V of the Clean Air Act, the Illinois Environmental Protection Agency is issuing this Acid Rain Program permit to Broadwing Energy Center.

SULFUR DIOXIDE (SO_2) ALLOCATIONS AND NITROGEN OXIDE (NOx) REQUIREMENTS FOR THE AFFECTED UNIT:

Affected Units: Cogeneration Unit 1 (CT-1)
SO_2 Allowances: This unit is not entitled to an allocation of SO_2 allowances pursuant to 40 CFR Part 73.
NO_X Limitation: This unit is not subject to a NO_X emissions limitation pursuant to 40 CFR Part 76.

PERMIT APPLICATION: The permit application, which includes SO_2 allowance requirements and other standard requirements, is attached and incorporated as part of this permit. The owners and operators of this source must comply with the standard requirements and special provisions set forth in the application

COMMENTS, NOTES AND JUSTIFICATIONS: This permit contains provisions related to SO_2 emissions and requires the owners and operators to hold SO_2 allowances to account for SO_2 emissions from the affected unit. An allowance is a limited authorization to emit up to one ton of SO_2 during or after a specified calendar year. The affected unit is a new unit and there is no allowance allocation for new units by USEPA. Although the unit is not eligible for an allowance allocation by USEPA, the owners or operators through their designated representative must obtain SO_2 allowances to cover emissions in accordance with the SO_2 allowance system requirements of 40 CFR Part 73. The transfer of allowances to and from a unit account does not necessitate a revision to the unit SO_2 allocations denoted in this permit (See 40 CFR 72.84).

This permit contains provisions related to NOx emissions and requires the owners and operators to monitor NOx emissions from the affected unit in accordance with applicable provisions of 40 CFR Part 75. This unit is not subject to a NOx emission limitation because USEPA has not adopted such limitations for combustion turbine generating units.

This Acid Rain Program permit does not authorize the construction and operation of the affected unit as such matters are addressed by Titles I and V of the Clean Air Act. This permit also does not affect the source's responsibility to meet all other applicable local, state and federal requirements, including state and federal requirements under the Clean Air Interstate Rule and 35 IAC Part 225, Subparts C, D, and E.

If you have any questions regarding this permit, please contact Joe Fraganato at 217/782-7088.

William D. Marr
Manager, Permit Section
Bureau of Air

WDM:JSF:

cc: USEPA Region 5

Attachment 3: Acid Rain Permit Application

1. Permit Requirements

a. The designated representative of each affected source and each affected unit at the source shall:

i. Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

ii. Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

b. The owners and operators of each affected source and each affected unit at the source shall:

i. Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

ii. Have an Acid Rain Permit.

2. Monitoring Requirements

a. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

b. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

c. The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

3. Sulfur Dioxide Requirements

a. The owners and operators of each source and each affected unit at the source shall:

i. Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

ii. Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

b. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

c. An affected unit shall be subject to the requirements under Condition 3(c)(i) as follows:

i. Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

ii. Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

d. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

e. An allowance shall not be deducted in order to comply with the requirements under Condition 3(c)(i) prior to the calendar year for which the allowance was allocated.

f. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

g. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

4. Nitrogen Oxides Requirements

a. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

5. Excess Emissions Requirements

a. The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.

b. The owners and operators of an affected source that has excess emissions in any calendar year shall:

i. Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

ii. Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

6. Recordkeeping and Reporting Requirements

a. Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:

i. The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

ii. All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

iii. Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and

iv. Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

b. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

7. <u>Liability</u>

a. Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

b. Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

c. No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

d. Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

e. Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

f. Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

g. Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

8. <u>Effect on Other Authorities</u>

a. No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

i. Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

ii. Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

iii. Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

iv. Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

v. Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.