ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

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CONSTRUCTION PERMIT/PSD APPROVAL
NSPS SOURCE - NESHAP SOURCE

PERMITTEE

Marquis Carbon Capture LLC
Attn: Elizabeth Steinhour
10000 Marquis Drive
Hennepin, Illinois 61327

Application No.: 23110009
Applicant's Designation:
I.D. No.: 155010ABH
Date Received: November 3, 2023
Subject: Carbon Capture Plant
Date Issued: June 23, 2025
Location: 10000 Marquis Drive, Hennepin, Putnam County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission units and air pollution control equipment consisting of a Carbon Capture Plant, 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 Daniel Rowell at 217/558-4368.

William D. Marr JMS 6/23/2025

William D. Marr
Manager, Permit Section
Bureau of Air

WDM:DBR:tan

DBR
6/23/25

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ATTACHMENT 1:

Summary of Changes in Emissions for the Project (Tons/Year)

Findings

1a. Marquis Carbon Capture LLC (MCC) has applied for a construction permit/Prevention of Significant Deterioration (PSD) approval to construct a carbon capture plant that would capture, compress, and sequester in an underground injection well carbon dioxide (CO_2) generated by certain process equipment from the nearby existing ethanol production complex owned and operated by Marquis Energy ("ME," BOA I.D. No. 155010AAJ; the "Ethanol Complex"). In particular, the carbon capture plant would capture and sequester CO_2 streams from the exhausts of fermentation scrubbers at the North and South Plants of the Ethanol Complex.

The proposed carbon capture plant would include three natural gas-fired boilers. Each boiler would be equipped with two ultra-low nitrogen oxides (NOx) dual burners, an economizer, flue gas recirculation (FGR), and a carbon monoxide (CO) catalyst.

The boilers would generate high-pressure steam to drive three steam turbines that would power three centrifugal Compressor/Dehydration Systems ("C/D Systems"). The C/D systems would compress and dehydrate CO_2 gas streams. In addition to a steam turbine, each C/D System would include a six-stage compressor train and a triethylene glycol (TEG) dehydration system.

Low-pressure steam exiting the C/D System turbines would be routed to the Ethanol Complex for use in the ethanol production processes. As part of this project, two existing natural gas-fired boilers, Boilers 3 and 21 at the Ethanol Complex, would be permanently shut down (See Condition 2.1.6(a) of this permit.)

During periods in which the C/D Systems are not operating, the boilers may be used to generate steam for use at the Ethanol Complex. The high-pressure steam would be stepped-down to low pressure steam through pressure relief valves. The steam generated by these boilers would not enable increases in the utilization of or processing capacity of the Ethanol Complex.

b. The proposed carbon capture plant would also include equipment to support the operation of the plant, including piping and piping equipment, an industrial circuit breaker, space heaters, roadways and parking areas, and a diesel-fired emergency generator.

c. The proposed carbon capture plant would be considered a single source with the existing Ethanol Complex and an existing Combined Heat and Power Plant ("CHP Plant") operated by Marquis LLC ("Marquis LLC;" BOA I.D. No. 155010ABA), rather than a new source, for purposes of the Illinois' rules for Prevention of Significant Deterioration (PSD), 35 IAC Part 204, Section 112 of the federal Clean Air Act, and Illinois' Clean Air Act Permit Program (CAAPP). This is because the proposed carbon capture plant would be constructed on the property of the Ethanol Complex; would be operated under common control (i.e., ME, Marquis LLC, and MCC are owned by the same parent company), and would serve as a support facility for the Ethanol Complex.

2. The facility would be located in Putnam County, which is designated as 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.

3a. This project would be a major project under Illinois' rules for PSD, 35 IAC Part 204, for emissions of particulate (as PM_{10} and $PM_{2.5}$) and greenhouse gases (GHGs), as carbon dioxide equivalents (CO_2e). This is because the increases in emissions of these pollutants would be greater than the applicable significant emission rates under Illinois' PSD rules.

b. The facility would not constitute a major project under the PSD rules for regulated NSR pollutants other than PM_{10}, $PM_{2.5}$, and GHGs (as CO_2e). This is because the increase in the emissions of these other pollutants would be less than the applicable significant emission rates under the PSD rules.

4. After reviewing the materials submitted by MCC, the Illinois EPA determined that the facility would be designed to: (i) comply with applicable state emission standards, (ii) comply with applicable federal emission standards, and (iii) utilize Best Available Control Technology (BACT) on emission units as required by PSD.

Note: For the pollutants that are subject to PSD, the determinations 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 emission units that are headed by "Control Technology Determination - BACT."

5. The Illinois EPA has determined that the application for the proposed carbon capture plant complies with Illinois' PSD rules, 35 IAC Part 204, and the requirements of other applicable state and applicable federal air pollution regulations.

6a. The air quality analyses submitted by MCC and reviewed by the Illinois EPA shows that the proposed project would not cause or contribute to violations of the National Ambient Air Quality Standards (NAAQS) for PM_{10} and $PM_{2.5}$. The air quality analysis also shows the impacts of the facility would be less than the significant impact levels for each pollutant.

b. Other impact analyses were also submitted by MCC, 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.

7. A copy of the application, the Project Summary prepared by the Illinois EPA for this application, and a draft of this construction permit were made available in a nearby public repository, and the public was given notice and an opportunity to examine this material and to submit comments on the draft permit.

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 carbon capture plant, 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 Coordination With Other Permits

a. This permit recognizes increases in utilization of an existing cooling tower system located at the South Ethanol Plant that is addressed by Subpart 2.11 of Construction Permit 17040028. In particular, this cooling tower system would be used to provide cooling water to the Compression/Dehydration Systems (Subpart 2.2 of this permit). For this purpose, this permit does not relax or revise applicability of emission limits and standards, operational and work practice requirements, requirements for sampling and analysis of cooling water, and recordkeeping and reporting requirements for the cooling tower system located at the South Ethanol Plant.

1.4 Nonapplicability Provisions

a. For pollutants other than PM_{10}, $PM_{2.5}$, and GHG, this permit is issued based on this project not being a major modification of the source for purposes of Illinois' rules for PSD, 35 IAC Part 204. This is because the increases in emissions of regulated New Source Review (NSR) pollutants other than PM_{10}, $PM_{2.5}$, and GHG are each less than significant. (See Attachment 1.)

b. This permit is issued based on the cooling tower system at the South Ethanol Plant, as addressed by Condition 1.3(a), not being subject to the application of Best Available Control Technology (BACT) for emissions of PM_{10} and $PM_{2.5}$. This is because the cooling tower would not be physically modified or undergo a change in the method of operation. As provided by Illinois' PSD rules, 40 CFR 204.1100(c), BACT shall be applied to each unit at which a net emissions increase would occur as a result of a physical change or change in the method of operation in the unit.

1.5 Requirements for Good Air Pollution Control Practice

a. At all times, the Permittee shall operate and maintain the new emissions units and any existing 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 3.5(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.

1.6 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 particulate matter (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) ("GHG (as CO_2e)").

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 nominally one hour in duration.

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

i. Compliance with annual 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 representative emission data for periods when such systems do not provide acceptable data.

ii. Compliance with annual 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. Compliance with annual limits for new emission units 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 for 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.

1.7 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.

1.8 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 behest 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.

1.9 General Recordkeeping Requirements

a. Pursuant to 35 IAC 204.1400(a), before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

i. A description of the project;

ii. Identification of the emissions unit or units whose emissions of PM could be affected by the project; and

iii. A description of the applicability test used to determine that the project is not a major modification for PM, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under 35 IAC 204.600(b)(3), and an explanation for why such amount was excluded.

b. Retention and Availability of Records:

i. All records, including logs and procedures, required by this permit shall be retained by the Permittee at a readily accessible location at the source for at least three years from the date of entry and shall be available for inspection by the Illinois EPA upon request. Any records retained in electronic format (e.g., computer) shall be capable of being retrieved and printed on paper during normal source office hours so as to be able to respond to an Illinois EPA request for records during the course of a source inspection. The Permittee shall provide copies of any required records requested by the Illinois EPA.

ii. The Permittee shall retrieve and print, on paper during normal source office hours, any records retained in an electronic format (e.g., computer) in response to an Illinois EPA request for records during the course of a source inspection.

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

1.10 Retention and Availability of Records

a. The Permittee shall retain all records and logs required by this permit for at least five years from the date of entry (unless a longer retention period is specified by a particular provision), keep the records at a location at the facility that is readily accessible to the Illinois EPA and USEPA, and make records available for inspection and copying by the Illinois EPA or USEPA upon request.

b. The Permittee shall retrieve and print on paper during normal facility office hours any records retained in an electronic format (e.g., computer) in response to an Illinois EPA or USEPA request for records during the course of a facility inspection or provide an electronic copy of such information in a format that is acceptable to the agency making the request.

1.11 Addresses for the Illinois EPA

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

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

Via Other Means
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.

1.12 Authorization to Operate Emission Units

a. Under this permit, the facility may be operated for a period that ends 180 days after initial startup of the carbon capture plant, to allow for commissioning, shakedown and required initial emission testing. This period may be extended by Illinois EPA for up to 180 days upon request of the Permittee if additional time is needed to complete commissioning, shakedown and required initial emission testing.

Note: For purposes of this permit, "commissioning" refers to the period of time prior to the operations of the facility being formally transferred from the firm that has designed and/or constructed the carbon capture plant to MCC, and "shakedown" refers to the period of time prior to demonstrating that the boilers and Compression/Dehydration Systems meet the facility design specifications. The period of time during which commissioning and shakedown occur is referred to as the "commissioning and shakedown period."

b. Upon successful completion of required initial emission testing, the Permittee may continue to operate emission units at the carbon capture plant provided that the Permittee submits a complete and timely application for Clean Air Act Permit Program (CAAPP) permit for the facility, as provided for by Section 39.5(5) of the Environmental Protection Act.

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

Part 2: Unit-Specific Conditions

Subpart 2.1: Natural Gas-Fired Boilers

2.1.1-1 Introduction

a. i. Three natural gas-fired boilers would be constructed for the purpose of supplying high-pressure steam to turbine-generators used to drive the compressor trains for the Compression/Dehydration Systems (Subpart 2.2). Each boiler would be equipped with two burners to produce high-pressure steam to drive the turbine-generators. High-pressure steam generated by the boilers may also be stepped-down, i.e., reduced to low-pressure steam, using pressure relief valves for use at the Ethanol Complex. Each boiler would have a nominal heat input capacity of 395 million British thermal units per hour (mmBtu/hr).

ii. Each boiler would be equipped with ultra low-NOx burners, an economizer, a flue gas recirculation (FGR) system, and CO catalysts. This equipment is expected to improve the overall operational efficiencies of the boilers as well as reduce emissions.

iii. This permit recognizes that piping and piping equipment in natural gas service would be installed to support the operation of the boilers. Piping and piping equipment have the potential to leak, resulting in methane emissions, which is a GHG, and VOM, which is a constituent of natural gas. Piping and piping equipment are addressed in Subpart 2.3.

b. As part of this project, two existing natural gas-fired boilers at the Ethanol Complex, Boilers 3 and 21, would be permanently shut down and either removed from the source or rendered permanently inoperable. This would result in a decrease in emissions from the boilers at the Ethanol Complex. These existing boilers would be shut down in "stages," i.e., an existing boiler would be shut down prior to the startup of a new boiler.

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 new natural gas-fired boilers identified in Condition 2.1.1-1(a) and listed below are referred to as the "affected boilers" and may also be referred to as the "new boilers." The existing natural gas-fired boilers addressed by Condition 2.1.1-1(b) and listed below are referred to as the "existing boilers."

Emission Unit/ Operation	Description	Control
Three Natural Gas-Fired Boilers (CCS Boilers 1 thru 3)	Natural gas-fired boilers, 395 mmBtu/hr heat input, each. Each boiler would include dual burners to produce high-pressure steam to drive the Compression/Dehydration System turbines. High-pressure steam generated by the boilers may also be reduced to low-pressure steam for use at the Ethanol Complex.	Ultra Low-NOx Burners FGR System CO Oxidation Catalyst System Economizer

2.1.2 Control Technology Determination - BACT

a. i. Each affected boiler shall be operated and maintained in conformance with the manufacturer's design, which shall include the following features:

A. Energy efficient design, including an economizer, a flue gas recirculation (FGR) system, a boiler blowdown heat recovery system, condensate recovery and steam air preheater.

B. Good combustion practices.

C. Good burner design capable of proper mixing air and fuel so as to provide efficient combustion of fuel.

D. Automated combustion management systems, including an oxygen trim system and inlet combustion air controls.

ii. The Permittee shall operate and maintain each affected boiler in accordance with good combustion practices, including firing the boilers on only natural gas, and implementation of good air pollution control practices to minimize emissions during startup and shutdown, which shall include operation of the affected boilers and associated air pollution control equipment in accordance with written operating procedures that include startup and shutdown.

b. i. Emissions of each affected boiler shall not exceed the following limits:

Pollutant	Limit (lbs/mmBtu)	Averaging Period
PM_{10}	0.0052	Rolling 3-hour Average
$PM_{2.5}$	0.004	Rolling 3-hour Average
GHG (as CO_2e)	117.1	Rolling 12-month Average

ii. A. Compliance with the PM_{10} and $PM_{2.5}$ emission limits shall be demonstrated emission testing requirements of Condition 2.1.9.

B. Compliance with the GHG emission limit shall be determined in accordance with 40 CFR 98 Subpart C, "General Stationary Fuel Combustion Sources," and the global warming potentials in 40 CFR 98 Subpart A.

2.1.3 Coordination With Other Permits

a. This permit does not revise or relax requirements addressing the operation of Boilers 3 and 21 at the Ethanol Complex. This permit recognizes the permanent shutdown of Boilers 3 and 21, which would occur as part of this project. Until Boilers 3 and 21 are shut down, these boilers shall continue to be subject to the applicable requirements for these boilers, as addressed by Subpart 2.1 of Construction Permit 17040028, including:

i. Applicable requirements of the New Source Performance Standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Db (the "Boiler NSPS"), and of the General Provisions of the NSPS, 40 CFR 60 Subpart A.

ii. Applicable requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD, and of the General Provisions of the NESHAP, 40 CFR 63 Subpart A.

iii. Applicable state emission standards, including 35 IAC 212.109, 212.123, and 216.121.

iv. Limits for natural gas usage of existing boilers.

v. Limits for hourly and annual emissions of existing boilers.

vi. Related testing, monitoring, recordkeeping, and reporting requirements.

2.1.4-1 Applicable Federal Emission Standards (NSPS)

a. The affected boilers are each subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Db (the "Boiler NSPS"), and the applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A. This is because construction of the affected boilers would commence after June 19, 1984 and each boiler would have a heat input greater than 100 mmBtu/hr.

b. For the affected boilers, the Permittee shall comply with the applicable emissions standards of the Boiler NSPS, including 40 CFR 60.44b, i.e., "Standard for nitrogen oxides," which

generally provides that no owner or operator of an affected facility, i.e., each affected boiler, that combusts only natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO_2) in excess of 0.10 lb/mmBtu (43 nanograms per Joule (ng/J)).

c. Pursuant to the General Provisions of the NSPS, 40 CFR 60.11(d), at all times the Permittee shall, to the extent practicable, maintain and operate the affected boilers including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

2.1.4-2 Applicable Federal Emission Standards (NESHAP)

a. The affected boilers are subject to the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD (the "Boiler NESHAP"), and the applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A. This is because the affected boilers would be located at a major source of HAP emissions.

b. For the affected boilers, the Permittee shall comply with all applicable requirements of the Boiler NESHAP for "Units designed to burn gas 1 subcategory," as defined at 40 CFR 63.7575, including the following:

i. The Permittee shall conduct periodic tune-ups of the affected boilers in accordance with 40 CFR 63.7540(a)(10), 63.7540(a)(12) and/or 63.7540(a)(13), as applicable.

ii. As generally provided by 40 CFR 63.7500(a)(3), at all times, the Permittee shall operate and maintain the affected boilers, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

2.1.4-3 Applicable State Emission Standards

a. i. The affected boilers are subject to 35 IAC 212.109 and 212.122(a), which provides that the emission of smoke or other particulate matter from each affected boiler shall not have an opacity greater than 20 percent, except as allowed by 35 IAC 212.122(b) and 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity readings in accordance with USEPA Reference Method 9.

ii. The affected boilers are subject to 35 IAC 212.301 and 212.314, 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 overhead at a point beyond the property line of

the source unless the wind speed is greater than 40.2 kilometers per hour (25 miles per hour).

b. The affected boilers are subject to the state emission standard for carbon monoxide at 35 IAC 216.121, which generally provides that no person shall cause or allow the emissions of CO into the atmosphere from fuel combustion units with a heat input greater than 10 mmBtu/hr to exceed 200 ppm, corrected to 50 percent excess air.

c. The affected boilers are subject to the applicable requirements of 35 IAC 217 Subpart U, including 35 IAC 217.454(a), 217.456(c), 217.456(e)(1)(B) through (D), and 217.456(e)(2). This is because, as generally provided by 35 IAC 217.454(a)(2)(A), each affected boiler is a fossil fuel-fired stationary boiler with a maximum design heat input greater than 250 mmBtu/hr and at no time serves a generator producing electricity for sale.

2.1.5 Nonapplicability Provisions

a. i. This permit is issued based on the affected boilers not being subject to the emissions standard under the Boiler NSPS for SO_2, 40 CFR 60.42b. This is because, as generally provided by 40 CFR 60.42b(k)(2), units firing only gaseous fuel with a potential SO_2 emission rate of 140 ng/J (0.32 lb/mmBtu) or less are exempt from the SO_2 emission limit of this NSPS. (See also Condition 2.1.7(a)(i).)

ii. This permit is issued based on the Permittee not being subject to the requirement under the Boiler NSPS, 40 CFR 60.48b(a), to install, operate and maintain a continuous opacity monitoring system (COMS) for the affected boilers. This is because, as generally provided by 40 CFR 60.48b(j)(2), a COMS would not be required as the affected boilers would only burn gaseous fuels (i.e., natural gas) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/mmBtu) or less and would not use a post-combustion technology to reduce SO_2 or PM emissions. (See also Condition 2.1.7(a).)

b. i. This permit is issued based on the affected boilers not being subject to the state emission standards for NOx emissions at 35 IAC 217 Subparts D and E. This is because each boiler would not be located at a source located in an area identified in 35 IAC 217.150(a)(1)(A).

ii. As generally provided by 35 IAC 217.451, this permit is issued based on the affected boilers not being subject to the requirements of the NOx Trading Program, 35 IAC 217 Subpart U, except for 35 IAC 217.454(a) and (b), 35 IAC 217.456(c), 217.456(e)(1)(B) through (D), and 217.456(e)(2). This is because, as provided by 35 IAC 217.451, the provisions of the NOx Trading Program have sunset.

c. This permit is issued based on the affected boilers not being subject to the federal Acid Rain program pursuant to Title IV of the Clean Air Act. This is because the affected boilers are industrial boilers that would not serve electrical generators that would supply electricity to any utility power distribution system for sale.

2.1.6 Operational Requirements and Limits

a. i. Within 30 days of shakedown and commissioning of the first affected boiler, one of the existing boilers addressed by Condition 2.1.1-1(b), i.e., Boilers 3 or 21, shall be permanently shut down and either removed from the source or rendered permanently inoperable.

ii. Within 30 days of shakedown and commissioning of the second affected boiler, both existing boilers addressed by Condition 2.1.1-1(b) shall be permanently shut down and either removed from the source or rendered permanently inoperable.

iii. Notwithstanding the timing specified in Conditions 2.1.6(a)(i) and (ii), the Illinois EPA may extend this 30-day period upon written request by the Permittee that shows that shakedown is ongoing and/or the ability of an affected boiler(s) to reliably operate has not yet been demonstrated so that more time is reasonably needed to complete the shakedown and commissioning of an affected boiler(s).

b. i. The maximum heat input capacity of each affected boiler shall not exceed 395 mmBtu/hr.

ii. Natural gas usage of the affected boilers shall not exceed 965 mmscf/month and 9,645 mmscf/year.

2.1.7 Emissions

a. Following shakedown and commissioning of the affected boilers:

i. Emissions of each affected boiler shall not exceed the following limits. Compliance with the NOx limit shall be determined on a 30-day rolling average basis. Compliance with the limits for pollutants other than NOx shall be determined on a 3-hour average.

Pollutant	Limits
	lb/mmBtu
NOx	0.017
CO	0.012
VOM	0.005
PM	0.0019
PM_{10}	0.0052
$PM_{2.5}$	0.004

SO_2	0.0006
GHG, as CO_2e	117.1

ii. Annual emissions of the affected boilers, i.e., combined emissions of the three boilers addressed in Condition 2.1.1-1(a)(i), shall not exceed the following limits:

Pollutant	Limits tons/year
NOx	83.23
CO	61.07
VOM	24.11
PM	9.16
PM_{10}	25.08
$PM_{2.5}$	19.29
SO_2	2.89
GHG, as CO_2e	564,652

b. i. Compliance with annual NOx emission limits addressed by Condition 2.1.7(a)(ii) shall be determined using the monitoring instrumentation required by Conditions 2.1.8(a) and (b).

ii. For pollutants other than NOx, compliance with annual emission limits addressed by Condition 2.1.7(a) shall be determined in accordance with Condition 1.6(f).

2.1.8 Monitoring Requirements

a. Pursuant to 40 CFR 60.48b(1), for each affected boiler, the Permittee shall install, calibrate, maintain, and operate a CEMS for measuring NOx and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system.

i. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of these CEMS. This CEMS shall be operated during all periods of operation of each affected boiler except for CEMS breakdowns and repairs. This CEMS shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive units operating days as specified and pursuant to 40 CFR 60.48b(f). Data is to be obtained in the scheduling and course of performing calibration checks, and zero and span adjustments as specified in the NSPS.*

* Fulfillment of the above criteria for availability of emission data from the CEMS does not shield the Permittee from potential enforcement for failure to properly maintain and operate the CEMS.

ii. The 1-hour average NOx emission rates measured by the CEMS shall be expressed in lbs/mmBtu heat input and shall be used to calculate average emission rates pursuant to the

NSPS. The 1-hour averages shall be calculated using the data points required under 40 CFR 60.13(h)(2).

iii. These CEMS shall also be used to determine compliance with the NOx limits in Condition 2.1.7(a).

b. For the affected boilers, as generally provided by 35 IAC 217.456(c)(1), the Permittee shall comply with the applicable monitoring provisions of 40 CFR 96 Subpart H.

c. For the affected boilers, the Permittee shall install, operate and maintain instrumentation to measure and record the combined fuel usage of the affected boilers (mmscf/month and mmscf/year).

2.1.9-1 Emission Testing Requirements

a. For the affected boilers, the Permittee shall fulfill the applicable testing requirements of the Boiler NSPS, including 40 CFR 60.46b.

b. Notwithstanding requirements for testing required by the Boiler NSPS, for the affected boilers, the Permittee shall have emissions testing conducted as follows, at its expense by a qualified testing service under maximum representative operation conditions, for emissions of CO, VOM, PM, PM_{10} and $PM_{2.5}$ and opacity using applicable USEPA Methods in accordance with Condition 3.1.

i. Testing shall initially be conducted within 12 months of completing shakedown and commissioning of each affected boiler. The Permittee may coordinate this initial test with the testing required by Condition 2.1.9-1(a).

ii. Thereafter, the Permittee shall have emissions testing conducted for the affected boilers at least once every 60 months, unless an operating permit issued for the source specifies a different frequency at which testing must be conducted.

c. The Permittee shall submit test plans, test notifications and test reports to the Illinois EPA in accordance with Condition 3.1.

d. In addition to other information required in a test report, test reports shall include the firing rate (mmBtu/hour).

2.1.9-2 CO Catalyst Sampling and Analysis

a. The Permittee shall conduct sampling and analysis for the catalyst material used in the CO catalyst system. Sampling and analysis events shall be conducted in accordance with the catalyst manufacturer's recommendations, including the frequency at which sampling and analysis is to be performed.

b. The Permittee shall maintain records for sampling and analysis events required by Condition 2.1.9-2(a) that address the following:

i. Date(s) sampling and analysis is performed.

ii. Identity of the affected boiler on which the CO catalyst system is sampled and analyzed.

iii. Results of analysis(es), including condition of the catalyst material.

iv. Manufacturer recommendations, including whether catalyst material(s) requires replacement and changes to the interval(s) at which sampling and analysis is recommended.

v. If catalyst materials are replaced, the identity of the affected boiler for which the catalyst material was replaced, with date.

2.1.10 Recordkeeping Requirements

a. For the affected boilers, the Permittee shall maintain applicable records required by the Boiler NSPS, including 40 CFR 60.49b, and the following:

i. The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day. [40 CFR 60.49b(d)(1)]

ii. For each "steam generating unit operating day," as defined by 40 CFR 60.41b, the owner or operator shall maintain records of the following information: [40 CFR 60.49b(g)]

A. Calendar date.

B. The average hourly NOx emission rates (expressed as NO_2) (ng/J or lb/mmBtu heat input) measured or predicted.

C. The 30-day average NOx emission rates (ng/J or lb/mmBtu heat input) calculated at the end of each steam generating unit operating day from the measured hourly NOx emission rates for the preceding 30 unit operating days.

D. Identification of the steam generating unit operating days when the calculated 30-day average NOx emission rates are in excess of the NOx emissions standard under 40 CFR 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

E. Identification of the steam generating unit operating days for which NOx emission data have

not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

F. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

G. For the CEMS, identification of the "F" factor used for calculations and method of determination.

H. Identification of the times when the pollutant concentration exceeded full span of the CEMS.

I. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification (PS) 2 and PS -3 or PS-16, respectively.

J. For the CEMS, the results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 60 Appendix F, Procedure 1.

iii. Pursuant to 40 CFR 60.49b(r)(1), the Permittee, as owner or operator of the affected boilers, shall obtain and maintain at the affected source fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the gaseous fuel meets the definition of "natural gas" at 40 CFR 60.41b.

b. For the affected boilers, the Permittee shall maintain applicable records required by the Boiler NESHAP, including 40 CFR 63.7555.

c. For the affected boilers, the Permittee shall maintain a file or other record containing the following information:

i. The rated design heat input capacity of each boiler, mmBtu/hour, with supporting documentation, if this is not provided by the nameplate attached to the unit.

ii. The Permittee's established operating and maintenance procedures for the affected boilers.

d. For the affected boilers, the Permittee shall maintain an operating log or other records that includes the information specified in Condition 3.4 and the following information:

i. Information for each startup and shutdown, including date, time and duration, as required by the General Provisions of the NSPS, 40 CFR 60.7(b).

ii. Information for any malfunction in the operation of the affected boiler or its air pollution control equipment,

as also required by the General Provisions of the NSPS, 40 CFR 60.7(b).

iii. Information for any incident in which the operation of an affected boiler(s) continued during malfunction or breakdown, including:

A. Date, time, and duration.

B. A description of the incident.

C. Whether emissions exceeded or may have exceeded any applicable standard or limit.

D. A description of the corrective actions taken to reduce emissions and the duration of the incident.

E. A description of the preventative actions taken to ensure no future reoccurrences.

e. For the affected boilers, the Permittee shall maintain records for the following information:

i. Fuel usage (scf/month and scf/year).

ii. Operating hours (hours/month and hours/year).

f. The Permittee shall maintain inspection, maintenance and repair log(s) or other similar records for the affected boilers that contain the information specified in Condition 3.4(b). For this purpose, these records shall also address changeout of catalyst material for the CO catalyst material.

g. For the affected boilers, the Permittee shall maintain the following records related to the boiler's emissions of NOx, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOM, and GHG:

i. A file containing the following information, with supporting documentation:

A. The emission factors used by the Permittee to determine each boiler's emissions of NOx, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOM, and GHG.

B. The maximum hourly emission rates of each boiler for NOx, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOM, and GHG.

ii. Records of the emissions of NOx, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOM, and GHG, of the affected boilers (lb/mmBtu, tons/month and tons/year), with supporting documentation and calculations.

2.1.11 Reporting and Notification Requirements

a. For the affected boilers, the Permittee shall fulfill the applicable reporting requirements of the Boiler NSPS, including 40 CFR 60.49b and 40 CFR 60.7(a)(3), and the following. The reporting period for the reports required under 40 CFR 60 Subpart Db is each 6-month period.

i. The Permittee shall submit to the Illinois EPA notification of the date of initial startup of each affected boiler, as provided by 40 CFR 60.7. This notification shall include the information in 40 CFR 60.49b(a)(1) through (4).

ii. The Permittee shall submit to the Illinois EPA the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in 40 CFR 60 Appendix B.

iii. The Permittee shall submit semiannual excess emission and monitoring system performance reports and/or summary report forms for the continuous monitoring device. Excess emissions are defined in 40 CFR 60 Subpart Db. [40 CFR 60.49b(h), 60.7(c), 60.7(d)]

iv. The Permittee shall submit the reports containing the information recorded under 40 CFR 60.49b(g). [40 CFR 60.49b(i) and 60.7(c)]

v. The Permittee shall submit the reports required by 40 CFR 60.49b(r), certifying that only natural gas was combusted in the affected unit during the reporting period.

b. For the affected boilers, the Permittee shall fulfill the applicable reporting and notification requirements of the Boiler NESHAP, including 40 CFR 63.7545 and 63.7550.

c. The Permittee shall notify the Illinois EPA within 30 days of the following events:

i. Startup of each affected boiler.

ii. Completion of shakedown of each affected boiler.

iii. The date each existing boiler is permanently shut down. This notification shall include the date that the boiler was permanently shut down.

d. For the affected boilers, the Permittee shall notify the Illinois EPA of deviations from the requirements of this permit for each affected boiler in accordance with Condition 3.5. For this purpose, such deviations shall be included with the reporting required by the NSPS, as addressed by Condition 2.1.11(a).

Subpart 2.2: Compression/Dehydration Systems

2.2.1-1 Introduction

a. i. Carbon dioxide (CO_2) is generated by the fermentation processes at the North and South Plants at the Ethanol Complex. In this project, a valve and piping would be installed on each of the two scrubbers controlling each the North and South Plants to divert the exhausts of these scrubbers to three compression/dehydration systems ("C/D System(s)") designed to compress and dehydrate CO_2 from these exhaust streams in preparation for sequestration in an underground injection well. Two C/D Systems would be operated simultaneously, with the third C/D System serving as a backup. Each C/D System would have a processing capacity of approximately 36 million standard cubic feet (scf) of CO_2. Annually, the C/D Systems are expected to process approximately 1.5 million metric tons of CO_2 from the Ethanol Complex.

ii. Each C/D System would include a six-stage compressor train powered by a steam turbine. The turbines would require high-pressure steam, which would be provided by the gas-fired boilers (Subpart 2.1). Low-pressure steam exiting the turbines would be sent to the Ethanol Complex for use in the ethanol production processes. In between the fifth and sixth stages of compression, gas streams would be dehydrated by a system that would contact gas streams directly with triethylene glycol (TEG), which would physically absorb moisture. The dehydration systems would include vents that would have the potential for emissions of VOM from the use of TEG and for emissions of GHG from the handling of CO_2. These emissions would vent directly to atmosphere. Periodic blowdown events of the C/D Systems, e.g., purging of a compressor system for planned maintenance, would also have the potential to emit VOM and GHG.

iii. Each C/D System would also include equipment to recover and reuse TEG, including filters (i.e., a sock filter and a carbon filter) to remove entrained solids, condensers, flash tanks, distillation columns, and a TEG regeneration reboiler, and a wastewater tank. Each wastewater tank would vent directly to the atmosphere. Steam necessary for the recovery of TEG would be supplied by the gas-fired boilers.

iv. Tanks would be constructed to store dehydration materials, i.e., TEG, for use in the C/D Systems. These tanks would have the potential for emissions of VOM and GHG from the storage and handling of dehydration materials that would be exhausted through vents on the tanks.

v. Piping and piping equipment used to transport CO_2 to an underground injection well would have the potential for

leaks of GHG. This piping and piping equipment is addressed in Subpart 2.3.

b. Following compression and dehydration, CO_2 gas streams would be transported by in-plant piping to an underground injection well located on contiguous property under common control to the property of the Ethanol Complex.

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 C/D Systems, TEG Recovery, and Solvent Storage Tanks identified in Condition 2.2.1-1(a)(i) through (iv) and listed below are referred to as the "affected C/D Systems."

Emission Unit/ Operation	Description
C/D Systems	Three six-stage compressor systems, each powered by a steam turbine. Each C/D System would have a processing capacity of 36 million scf. Direct contact with TEG would be used to dehydrate gas streams processed by the system between the fifth and sixth stages of compression. TEG would be recovered for reuse. Following compression and dehydration, CO_2 gas streams would be transported by in-plant piping for injection in an underground well. Emissions of GHG would occur from the vents on the dehydration units and during blowdown events.
TEG Recovery	Equipment used in the recovery of TEG for reuse. TEG recovery equipment would include filters, condensers, and reboilers. This equipment would include vents that would exhaust VOM directly to the atmosphere.
Solvent Storage Tanks	Tanks used to store absorption solvents (i.e., TEG). Each tank would include a vent that would exhaust VOM directly to the atmosphere.
Wastewater Tanks	Tanks used to store wastewater generated by the dehydration step in the C/D Systems for further processing. Each tank would include a vent that would exhaust GHG and VOM directly to atmosphere.

2.2.2 Control Technology Determination - BACT

a. The affected C/D Systems shall be designed, operated, and maintained in accordance with good operating practices and good air pollution control practices to meet the following limits for GHG. For this purpose, the Permittee shall operate and maintain the affected C/D Systems in accordance with written procedures developed and maintained by the Permittee. These procedures shall, at a minimum, incorporate the manufacturer's recommendations for operation and maintenance of the C/D Systems.

i. Blowdown events for the affected C/D Systems shall not exceed 72 events based on a rolling 12-month total.

ii. Emissions of GHG from the vents of the C/D Systems, including the vents of the dehydration units and wastewater tanks, shall not exceed 1,060.40 tons/year.

iii. Emissions of GHG (as CO_2e) from purging and blowdown events for the affected C/D Systems shall not exceed 145.72 tons/year based on a rolling 12-month total.

b. For purposes of determining compliance with the limits in Condition 2.2.2(a)(i), (ii), and (iii) the Permittee shall maintain records for the number of blowdown events (events/year) and determine GHG emissions based on site-specific emission factors with supporting documentation and calculations and the global warming potentials in 40 CFR 98 Subpart A.

2.2.3 Applicable State Emission Standards

a. The affected C/D Systems are each 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 other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

b. The affected tanks are each subject to 35 IAC 215.122(b), which generally provides that no person shall cause or allow the loading of any organic material into any stationary tank having a storage capacity of greater than 946 1 (250 gal), unless such tank is equipped with a permanent submerged loading pipe, submerged fill, or an equivalent device approved by the Illinois EPA according to the provisions of 35 IAC 201 or unless such tank is a pressure tank as described in 35 IAC 215.121(a) or is fitted with a recovery system as described in 35 IAC 215.121(b)(2).

c. The affected C/D Systems and affected tanks are each subject to 35 IAC 215.301, which provides that no person shall cause or allow the discharge of 8 lbs/hour of organic material from an emission source, unless the emissions do not qualify as photochemically reactive material as defined by 35 IAC 211.4960 and do not contribute to an odor nuisance.

2.2.4 Operational Requirements and Limits

a. The Permittee shall operate and maintain the affected C/D Systems and affected tanks in accordance with good air pollution control practices for minimizing emissions.

b. The capacity of each wastewater tank addressed by Condition 2.2.1-1(a)(iii) shall not exceed 1,000 gallons.

c. The capacity of each solvent storage tanks addressed by Condition 2.2.1-1(a)(iv) shall not exceed 1,000 gallons.

2.2.5 Emissions

a. This permit is issued based on minimal emissions of VOM from solvent storage tanks and wastewater tanks, i.e., emissions of no more than 0.44 tons/year.

2.2.6 Monitoring and Instrumentation

a. The Permittee shall install, calibrate, operate, and maintain the following:

i. Instrumentation to monitor the position of the valves installed on each of the North and South Plant scrubbers.

ii. Instrumentation to continuously measure and record the mass flow rate of gas processed by the affected C/D System (lbs/hour, total).

iii. Instrumentation to measure the TEG used in the affected C/D Systems. The Permittee shall maintain a log for the amount of TEG used to charge and replenish the affected C/D systems at the end of each operating day (lb/day).

iv. A. For the TEG recovery system described in Condition 2.2.1-1(a)(iii), instrumentation to continuously monitor the pressure drop across each of the sock and carbon filters (pounds per square inch (psi)).

B. The Permittee shall establish and maintain appropriate set points for the pressure drop across each sock and carbon filter.

C. The Permittee shall record the pressure drop across each sock filter at least once per operating day.

D. If the pressure drop at a sock filter, as recorded in accordance with Condition 2.2.6(a)(iv)(C), is outside the normal operating range established in accordance with by Condition 2.2.6(a)(iv)(B), the Permittee shall investigate the cause of the variation in pressure drop and initiate appropriate corrective action measure(s) within 24 hours to restore the pressure drop to within the established operating range. The pressure drop shall be restored to the established operating range within 48 hours of the pressure drop being outside of the normal operating range.

2.2.7 Recordkeeping Requirements

a. The Permittee shall maintain an operating log or other similar records for the affected C/D Systems that include the information specified in Condition 3.4(a) and the following information:

i. Records for the amount of gas processed by the affected C/D System (lbs/month and tons/year, total).

ii. Records for the TEG usage of each affected C/D System (pounds or tons/month and pounds or tons/year).

b. The Permittee shall maintain the following records related to the emissions of VOM and GHG from the affected C/D Systems:

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

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

iii. Records for emissions of VOM and GHG from purging and blowdown events. These records shall also include the date and duration of each purging and blowdown event.

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

i. Identification of material stored.

ii. Tank design specification demonstrating use of submerged fill pipes.

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

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

2.2.8 Reporting and Notification Requirements

a. The Permittee shall notify the Illinois EPA with 30 days of the following events:

i. Startup of each affected C/D System.

ii. The date CO_2 is first injected into an underground injection well.

iii. The date that the underground injection well addressed in Condition 2.2.1-1(a) is no longer used.

iv. The date that the Permittee applies to USEPA and/or other jurisdictional authorities for construction of additional underground injection wells.

b. For the affected C/D Systems, the Permittee shall promptly notify the Illinois EPA of deviations from the requirements of this permit for the affected C/D Systems, in accordance with Condition 3.5.

Subpart 2.3: Piping and Piping Equipment

2.3.1-1 Introduction

a. Piping and piping equipment, such as flanges, connectors, valves, and pressure relief valves, would be constructed to support the operation of the carbon capture plant, delivering natural gas to the Boilers (Subpart 2.1) and transporting CO_2 from the C/D Systems for sequestration (Subpart 2.2).

Piping and piping equipment handling natural gas for the boilers and CO_2 from the C/D Systems have the potential to leak. Since natural gas is primarily methane (CH_4), which is a greenhouse gas (GHG), piping and piping equipment handling natural gas would have the potential to emit GHG as they leak. Emissions of VOM may also occur from the non-methane constituents of natural gas. Piping and piping equipment handling CO_2 from the C/D Systems would also be emitted during blowdown events and may also have the potential to emit GHG as they leak. 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 components."

2.3.1-2 List of Emissions Units an Air Pollution Control Equipment

For purposes of the unit-specific conditions addressed by this Subpart 2.3, the components identified in Condition 2.3.1-1(a) and listed below is referred to as the "affected components."

Emission Unit/ Operation	Description	Control
Piping Components and Equipment	Piping components and piping equipment handling natural gas or CO_2 with the potential for leaks (Connectors, Valves, Pump Seals, Sampling Connections, Drains and Pressure Relief Valves).	LDAR Program

2.3.2 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, use of high-quality components that are designed for the specific service in which they are employed, shall be installed and operated.

b. The Permittee shall implement a noninstrumental LDAR program, including the completion of auditory, visual and olfactory

(AVO) inspections on a monthly basis to identify any components that are leaking.

c. The Permittee shall implement an instrument-based LDAR program, including use of Optical Gas Imaging and USEPA Method 21, as follows:

i. For affected components, emissions from leaks shall be controlled by meeting requirements of the NSPS for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015, 40 CFR 60 Subpart OOOOa, including relevant portions of the NSPS for work practices, testing, recordkeeping and reporting. In particular, the Permittee must:

A. Monitor all affected components in accordance with 40 CFR 60.5397a(b) through (g), except that use of an optical gas imaging instrument shall be used as an alternative to inspecting for leaks in accordance with USEPA Method 21, unless the Permittee demonstrates to the Illinois EPA that, as applied to methane, optical gas imaging would not be equally or more effective in the identification of leaks than USEPA Method 21;

B. 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;

C. Repair all sources of fugitive emissions in accordance with 40 CFR 60.5397a(h);

D. Keep records in accordance with 40 CFR 60.5397a(i); and

E. Submit reports in accordance with 40 CFR 60.5397a(j).

ii. For purposes of monitoring of the affected components, fugitive emissions are defined as any visible emissions from an affected component observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of 40 CFR 60 Appendix A-7.

d. Pipe blowdown events shall not exceed 2 events per year based on a running 12-month total.

e. Emissions of GHG (as CO_2e) from affected components resulting from piping equipment and pipe blowdown events, in total, shall not exceed 135.66 tons/year based on a running 12-month total.

2.3.3 Nonapplicability Provisions

a. This permit is issued based on the affected components not being subject to the requirements of the NSPS for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015, 40 CFR 60 Subpart OOOOa. This is because the carbon capture plant is not a Crude Oil and Natural Gas Production source category, as defined in 40 CFR 60.5430a. Note, however, for the affected components, the Permittee must meet requirements of this NSPS as required by Condition 2.3.2(c)(i).

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

2.3.4 Operating Requirements

a. The Permittee shall maintain the affected components in accordance with good air pollution control practice for minimizing emissions.

2.3.5 Emissions

a. This permit is issued based on minimal emissions of VOM from affected components, i.e., emissions of no more than 0.01 tons/year.

2.3.6 Recordkeeping Requirements

a. The Permittee shall maintain a log of each instance where a high-quality component was installed rather than a leakless component, with justification for why a leakless component was not available or technically feasible. This documentation shall be retained until the particular component is no longer present at the source:

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

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

iii. An explanation of why a leakless component was not installed if one was available and technically feasible.

b. In addition to the records required by Condition 2.3.2(c)(i)(D), the Permittee shall also maintain a log or other records for each monthly noninstrumental 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 components, the Permittee shall maintain a log or other records that identify leaking components and a compilation of leaking components by month by type of component, the nature of the leaks, and the duration of the leaks.

d. For the affected components, the Permittee shall maintain records for the number of blowdown events (events/year).

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

i. A file containing the number of components by type and service, and emission factors used by the Permittee to determine the emissions from leaks in different types of components, 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 plant.

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

2.3.7 Reporting Requirements

a. i. The Permittee shall promptly notify the Illinois EPA of deviations from the requirements of this permit for affected components, as follows. Reports 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 2.3.2(c)(i)(D), shall be reported in such reports.

Subpart 2.4: Circuit Breaker

2.4.1-1 Introduction

a. A circuit breaker, i.e., a new 6-way switch, would be installed as part of the project. The circuit breaker would use pressurized gas as a dielectric, or insulating, material. Although the circuit breaker would normally be pressurized without any vents for direct emissions, leaks of insulating materials, which has the potential for GHG emissions, may occur resulting in GHG emissions to the atmosphere. To reduce potential emissions of GHG from leaks, the circuit breaker would use a composite mixture of insulating gasses with low global warming potential (GWP).

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

For purposes of the unit-specific conditions addressed by this Subpart 2.4, the circuit breaker identified in Condition 2.4.1-1(a) and listed below is referred to as the "affected circuit breaker."

Emission Unit/ Operation	Description	Control
Circuit Breaker	Circuit breaker that uses a dielectric or insulating material.	Insulating Material with Low GWP LDAR Program

2.4.2 Control Technology Determination - BACT

a. The affected circuit breaker shall be a low leak rate design circuit breaker, guaranteed by the manufacturer to have a GHG (as CO_2e) leak rate of no more than 0.5 percent on a calendar-year basis.

b. The affected circuit breaker shall be installed with composite insulating material, consisting of a mixture of insulating gas and CO_2, or such other insulating gasses, with a composite GWP of no greater than 292.

c. The Permittee shall develop, implement, and maintain a written Leak Detection and Repair (LDAR) Program for the affected circuit breaker that includes the use of instrumentation to measure the level of insulating material in the circuit breaker.

d. i. The total emissions of GHG (as CO_2e) from the affected circuit breaker shall not exceed 0.02 tons/year, on a calendar year basis.

ii. Compliance with the above limit for GHG shall be determined using the relevant procedures for quantification of GHG emissions in 40 CFR 98 Subpart DD, "Electrical Transmission and Distribution Equipment Use," and the global warming potentials in 40 CFR 98 Subpart A.

2.4.3 Work Practice Requirements

a. If a leak is detected from the affected circuit breaker, as monitored in accordance with the written LDAR Program required by Condition 2.4.2(c), the Permittee shall perform all action(s) necessary to eliminate the leak as soon as practicable but no later than 21 days; however, if the leak cannot be repaired within 21 days without the shutdown of the boilers or C/D Systems addressed by Subparts 2.1 or 2.2, respectively, the leak shall be repaired during the next planned shutdown of the plant.

2.4.4 Operational Monitoring and Instrumentation Requirements

a. The Permittee shall maintain the following records for the instrumentation used to measure the levels of insulating gases in the affected circuit breaker:

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

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

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

2.4.5 Recordkeeping Requirements

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

i. The manufacturer and model number of the affected circuit breaker and its GHG (as CO_2e) content when fully charged. This record shall also address the manufacturer-recommended percent ratio of each insulating material used.

ii. A copy of the manufacturer's guarantee for the design leak rate of GHG (as CO_2e) from the affected circuit breaker (percent loss).

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

iv. Documentation for the GWP for each insulating gas used and, if a mixture of insulating gases are used, the composite GWP of the mixture of insulating gases, expressed as CO_2e.

b. i. The Permittee shall maintain records for the addition of insulating gas(es) to affected circuit breaker following initially being filled or charged with insulating gas, with date, the amount of insulating gas added (in hundredths of pounds, by

type), 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 insulating gas to the affected circuit breaker, in hundredths of pounds, based on inventory data for gas:

A. The amount of insulating gas(es) initially charged to the circuit breaker (pounds, by type).

B. The subsequent addition of insulating gas to the circuit breaker following initial charging of the units (pounds/month, by type).

c. i. The Permittee shall maintain records of the annual leak rate from affected circuit breaker, calculated as the total amount of insulating gas added to the circuit breaker in a calendar year, as recorded pursuant to Condition 2.4.4(b)(i), and the amount of gas in the unit when fully charged, as recorded pursuant to Condition 2.4.4(a)(i).

ii. The Permittee shall maintain records for the total emissions or loss of GHG (as CO_2e) from the affected circuit breaker (tons/month and tons/year), as determined from the methodology required by Condition 2.4.2(d), with supporting calculations.

2.4.6 Reporting Requirements

a. For the affected circuit breaker, the Permittee shall promptly notify the Illinois EPA of deviations from the requirements of this permit for the affected circuit breaker, in accordance with Condition 3.5.

b. The Permittee shall notify the Illinois EPA within 30 days of completion of construction of the affected circuit breaker.

Subpart 2.5: Space Heaters

2.5.1-1 Introduction

a. Natural gas-fired space heaters would be used during cold weather to heat the interior of the carbon capture plant to prevent equipment damage during periods in which the boilers (Subpart 2.1) are offline.

b. Under Illinois' air pollution control regulations, as these heaters would directly heat air and would not have separate vents for combustion emissions, these heaters are regulated as process emission units because they are designed for direct, rather than indirect, heat transfer.

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

For purposes of the unit-specific conditions addressed by this Subpart 2.5, natural gas space heaters identified in Condition 2.5.1-1(a) and listed below are referred to as "affected space heaters."

Emission Unit/ Operation	Description
Space Heaters	Natural gas-fired space heaters used to provide heat for purposes of preventing equipment damage and for comfort heating.

2.5.2 Control Technology Determination - BACT

a. i. Natural gas shall be the only fuel fired in the affected space heaters.

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

b. i. Emissions of PM_{10} and $PM_{2.5}$ of each affected space heater shall not exceed 0.0005 and 0.0004 lb/mmBtu, respectively.

ii. Emissions of GHGs (as CO_2e) from each affected space heater shall not exceed 117.1 lb/mmBtu.

c. For purposes of determining compliance with the limits for GHG emissions in Condition 2.5.2(b)(ii), the Permittee shall determine GHG emissions in accordance with 40 CFR 98 Subpart C, "General Stationary Fuel Combustion Sources," and the global warming potentials in 40 CFR 98 Subpart A.

2.5.3 Applicable State Emission Standards

a. The affected space heaters 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, 6-minute average, from any emission unit, except as allowed by 35 IAC 212.123(b) and 212.124.

b. The affected space heaters are subject to 35 IAC 212.301 and 212.314, 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 overhead at a point beyond the property line of the source unless the wind speed is greater than 40.2 kilometers per hour (25 miles per hour).

c. The affected space heaters are subject to 35 IAC 214.301, which provides that no person shall cause or allow the emissions of SO_2 into the atmosphere from any process emission source to exceed 2000 ppm.

2.5.4 Nonapplicability Provisions

a. This permit is issued based on the affected space heaters not being subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Dc. This is because each affected space heater is not a "steam generating unit" as defined at 40 CFR 60.41c, as it directly heats air.

b. This permit is issued based on the affected space heaters not being subject to the NESHAP for Industrial, Commercial and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD. This is because each affected space heater is not a "process heater" as defined at 40 CFR 63.7575. This is because the space heaters' primary purpose is not to transfer heat indirectly to a process material (liquid, gas, or solid) and not to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit. In addition, each affected space heater is not a "boiler" as defined at 40 CFR 63.7575. This is because each affected space heater would not have the primary purpose of recovering thermal energy in the form of steam or hot water.

c. This permit is issued based on the affected space heaters not being subject to 35 IAC 212.321 for particulate matter emissions. This is because this rule cannot reasonably be applied to these units since the definition for process weight rate, 35 IAC 211.5250, provides that gaseous fuel and combustion are excluded when determining the process weight rate of a process.

2.5.5 Operating Requirements

a. The usage of fuel by the affected space heaters shall not exceed 2.1 million scf/month and 12.3 million scf/year.

b. The total rated design heat input capacity of the affected space heaters shall not exceed 3.41 mmBtu/hour.

2.5.6 Emissions

a. The emissions of the affected space heaters, in total, shall not exceed the following limits:

Pollutant	Limits	
	Pounds/Hour	Tons/Year
NOx	0.34	0.61
CO	0.29	0.51
PM	-	0.01
$PM_{10}/PM_{2.5}$	-	0.01
GHG (as CO_2e)	-	720.17

b. This permit is issued based on negligible emissions of VOM, SO_2 and PM from the affected space heaters, i.e., total annual emissions of no more than 0.03, 0.01 and 0.01 tons per year, respectively.

2.5.7 Recordkeeping Requirements

a. The Permittee shall maintain the following records for the affected space heaters:

i. A file containing the following information for each affected space heater: manufacturer, model name and serial number or other unique identification for the heater: and the rated design heat input capacity of the heater (mmBtu/hour).

ii. An operating log or other similar records for the affected space heaters in accordance with Condition 3.3(a).

iii. An inspection, maintenance, and repair log or other similar records for the affected space heaters in accordance with Condition 3.3(b).

b. Records for the total amount of fuel burned in the affected space heaters (mmscf/month and mmscf/year). This data may either be determined by direct metering of the fuel usage of the affected space heaters or derived from capacity and operational data for the collection of the various units whose fuel usage is metered to apportion the fuel usage between the affected space heaters and the other units whose fuel usage is metered.

c. The Permittee shall maintain the following records related to emissions of NOx, CO, PM and $PM_{10}/PM_{2.5}$ of the affected space heaters:

i. A file containing a determination of the maximum emission rates of each pollutant (lbs/mmBtu and lbs/hour), with supporting documentation.

ii. Records of the actual emissions of each pollutant from all affected space heaters, combined (tons/month and tons/year), with supporting calculations.

d. The Permittee shall maintain records for the GHG (as CO_2e) emissions of the affected space heaters (lb/mmBtu, tons/month and tons/year), with supporting calculations.

2.5.8 Reporting Requirements

a. For the affected space heaters, the Permittee shall promptly notify the Illinois EPA of deviations from the requirements of this permit for the affected space heaters, in accordance with Condition 3.5.

Subpart 2.6: Roadways and Parking Areas

2.6.1-1 Introduction

a. Fugitive dust (particulate emissions) would be generated by vehicle traffic on roadways and parking areas at the complex. The carbon capture plant would be served by approximately one quarter mile of roadway for maintenance trucks and periodic delivery of process chemicals. Emissions of particulates (PM, PM_{10}, and $PM_{2.5}$) would be controlled by paving all roadways, which handle all the traffic coming into or leaving the plant, and implementation of dust control measures, including sweeping and application of dust suppressing materials, if necessary.

2.6.1-2 List of Emissions 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(a) and listed below is referred to as "affected roadways and parking areas."

Emission Unit/ Operation	Description	Control
Roadways and Parking Areas	Paved roads and parking areas serving the carbon capture plant.	Paving Sweeping Dust Suppression Application

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 the following to comply with the limits in Conditions 2.6.2(a), 2.6.3 and 2.6.5:

i. Weekly vacuum sweeping with wet suppression, 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.

2.6.3 Applicable State Emission Standards

a. For the affected roadways and parking areas, the Permittee shall comply with 35 IAC 212.301 and 212.314, which provides that emissions of fugitive particulate matter shall not be visible 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

a. 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 Emissions

a. Emissions of PM, PM_{10}, and $PM_{2.5}$ from the affected roadways and parking areas shall not exceed 0.05, 0.01, 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 carbon capture plant, 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 3.1.

i. Observations shall first be completed no later than 30 days after the startup of the carbon capture plant.

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, 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. Logs for determinations of visible emissions shall 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 that contains:

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 carbon capture 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 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 data for the activities at the carbon capture plant, the above records for the affected roadways including data for implementation of the Fugitive Dust Control Plan, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

2.6.9 Reporting Requirements

a. 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 3.5.

Subpart 2.7: Emergency Engine

2.7.1-1 Introduction

a. One diesel-fired emergency engine generator with a maximum power output of 600 kilowatts (kW) would supply electricity to critical plant equipment during power outages. Other than during power outages, this engine would only be operated for purposes of maintenance checks and readiness testing, normally for less than an hour per week.

b. This permit also recognizes that a tank used to store diesel fuel for use in the emergency engine would be installed. This tank is exempt from construction permitting requirements pursuant to 35 IAC 201.146(n)(3).

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

For purposes of the unit-specific conditions addressed by this Subpart 2.7, the diesel-fired emergency engine identified in Condition 2.7.1-1(a) and listed below is referred to as the "affected engine."

Emission Unit/ Operation	Description
Emergency Engine	Diesel-fired emergency engine with a rated power output of 600 kW.

2.7.2 Control Technology Determination - BACT

a. Ultra-low sulfur diesel shall be the only fuel fired in the affected engine.

b. The affected engine shall be operated and maintained in accordance with good combustion practices.

c. i. The affected engine shall be designed and operated to comply with the applicable limits of the New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII, for emergency engines other than fire pump engines. (See Condition 2.7.3-1(a)(ii)).

ii. Emissions of PM_{10} and $PM_{2.5}$ shall not exceed the following limits, in terms of grams per kilowatt-hour (g/kW-hr):

Pollutant	Limits
	g/kW-hr
PM_{10}	0.20
$PM_{2.5}$	0.20

d. The affected engine shall not exceed the operational limit in Condition 2.7.5(e).

e. GHG (as CO_2e) emissions of the affected engine shall not exceed 222.5 tons/year. Compliance with this limit shall be determined using emission factors for GHGs in 40 CFR 98 Subpart C, "General Stationary Fuel Combustion Sources," and the global warming potentials in 40 CFR 98 Subpart A.

2.7.3-1 Applicable Federal Emission Standards

a. This permit is issued based on the affected engine being an "emergency" stationary compression ignition (CI) reciprocating internal combustion engine (RICE), as defined in:

i. The New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engine, 40 CFR 60 Subpart IIII (the "Engine NSPS").

ii. The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engine, 40 CFR 63 Subpart ZZZZ (the "Engine NESHAP").

b. The affected engine is subject to the Engine NSPS. For the affected engine, the Permittee shall comply with the applicable requirements of the Engine NSPS and the related requirements of the General Provisions of the Engine NSPS, 40 CFR 60 Subpart A.

i. The affected engine is subject to the applicable requirements for 2007 model year or later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 hp) and a displacement of less than 30 liters per cylinder that are not fire pump engines. Pursuant to 40 CFR 60.4205(b) and 60.4206, for the affected engine, the Permittee must comply with the emission standards in 40 CFR 60.4202(a)(2) addressed below over the entire life of the engine.

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

ii. Pursuant to 40 CFR 60.4205(b), 60.4202(a)(2), and 40 CFR 1039.105(b), smoke from the affected engine shall not exceed the following smoke standards:

A. 20 percent during acceleration.

B. 15 percent during lugging mode.

C. 50 percent during the peaks in either acceleration or lugging modes.

iii. Pursuant to 40 CFR 60.4207(b), the diesel fuel used in the affected engine shall meet the requirements of 40 CFR 1090.305 for nonroad diesel fuel.

iv. Pursuant to 40 CFR 60.4211(a), the Permittee shall operate and maintain the affected engine according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer. The Permittee shall also meet any applicable requirements of 40 CFR Part 1068 for the affected engine.

v. The Permittee shall operate the affected engine with the applicable requirements of 40 CFR 60.4211(f)(1) through (3) for the emergency stationary CI RICE.

vi. Pursuant to 40 CFR 60.11(d), the Permittee shall, to the extent practicable, maintain and operate the affected engine including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions, at all times, including periods of startup, shutdown, and malfunction.

c. This permit is issued based on the affected engine only being subject to certain operating requirements of the Engine NESHAP, including 63.6640(f), and the initial notification requirements of 40 CFR 63.6645(f). No further requirements for the affected engine apply under the Engine NESHAP. This is because, pursuant to 40 CFR 63.6590(b)(i), the affected engine is a new emergency stationary RICE with a site rating of more than 500 brake horsepower located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 63.6640(f)(2)(ii) and (iii).

2.7.3-2 Applicable State Emission Standards

a. The affected engine is subject to the state emission standard for opacity of visible emissions at 35 IAC 212.123(a), which generally 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 engine is subject to the state emission standard for emissions of sulfur dioxide (SO_2) at 35 IAC 214.301, which generally provides that no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission source to exceed 2000 ppm.

c. For the affected engine, the Permittee shall comply with the applicable fuel sulfur content limitations of 35 IAC 214.305(a)(2), which generally provides that the sulfur content of all distillate fuel oil must not exceed 15 ppm.

2.7.4 Nonapplicability Provisions

a. This permit is issued based on the affected engine not being subject to the requirements of 35 IAC Part 212 Subpart L, because a process weight rate cannot be set (pursuant to 35 IAC 211.5250, liquid fuels and combustion air are not included), due to the nature of such unit, so that these rules cannot reasonably be applied, pursuant to 35 IAC 212.323.

2.7.5 Operational Limits and Work Practices

a. The rated capacity of the affected engine shall not exceed 600 kW.

b. Pursuant to 40 CFR 60.4211(a), except as provided by 40 CFR 60.4211(g), the Permittee shall operate and maintain the affected engine according to the manufacturer's written instructions related to emissions. In addition, the Permittee may only change those emission-related settings that are permitted by the manufacturer. The Permittee must also meet the requirements of 40 CFR Part 1068, as applicable.

c. Pursuant to 40 CFR 60.4211(f), the affected engine may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of the affected engine shall not exceed 100 hours per year. The affected engine may also operate up to 50 hours per year in non-emergency situations, but those 50 hours count towards the 100 hours per year provided for maintenance and testing. This operation in non-emergency situations cannot be for peak shaving or to generate income for a source to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as provided herein, is prohibited.

d. i. Maintenance checks and readiness testing of the affected engine to confirm their readiness for emergency operation shall be conducted during daylight hours.

ii. The duration of maintenance checks and readiness testing of an affected engine to confirm readiness shall only exceed one hour in a day if operational problems are encountered during initial readiness testing of the affected engine and further testing of the affected engine is needed to confirm readiness after corrective actions have been taken.

e. The affected engine shall not operate for more than 500 hours/year.

2.7.6 Emissions

a. i. The emissions of the affected engine shall not exceed the following limits:

Pollutant	Limits Tons/Year
NOx	2.12
CO	1.16
PM	0.07
$PM_{10}/PM_{2.5}$	0.07

ii. This permit is issued based on minimal emissions of VOM, and SO_2 from the affected engines, i.e., emissions of no more than 0.23 and 0.41 tons/year, each pollutant.

2.7.7 Operational Monitoring

a. Pursuant to 40 CFR 60.4209(a), for the affected engine, the Permittee shall install, operate, and maintain a non-resettable hour meter.

2.7.8 Recordkeeping Requirements

a. Pursuant to 40 CFR 60.4214(b), if the affected engine does not meet the standards of the NSPS, 40 CFR 60 Subpart IIII, applicable to non-emergency engines in the applicable model year, the Permittee must maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The Permittee must record the time of operation of the engine and the reason the engine was in operation during that time.

b. i. As generally provided by 35 IAC 214.205(a)(3)(A), for the affected engine, the Permittee shall maintain records demonstrating that the fuel oil used by the affected engine complies with the requirements 35 IAC 214.205(a)(1) and (a)(2), such as records from the fuel supplier indicating the sulfur content of the fuel oil.

ii. As generally provided by 35 IAC 214.205(a)(3)(B), the Permittee shall retain these 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. The Permittee shall maintain a file for the affected engine containing copies of the certifications from the manufacturers for the emission rates of the engine and their fuel consumption rates, in gallons per kW-hour.

d. The Permittee shall maintain records for the maintenance checks and readiness testing of the affected engine that address compliance with Condition 2.7.5(d), including:

i. The date and timing of the maintenance check or readiness testing;

ii. If maintenance checks or readiness testing is conducted outside of daylight hours, the reason for the timing of such testing; and

iii. If the duration of the maintenance checks and readiness testing of an affected engine in a day is more than one hour, the reason why the maintenance checks and readiness testing could not be completed within one hour.

e. The Permittee shall maintain records for the operating hours of the affected engine (hours/month and hours/year).

f. The Permittee shall maintain records for the amount of fuel used by the affected engine (gallons/month and gallons/year).

g. The Permittee shall maintain the following records related to emissions of NOx, CO, SO_2, VOM, PM, $PM_{10}/PM_{2.5}$, and GHG (as CO_2e):

i. A file containing the following information, with supporting documentation and calculations:

A. The maximum emission rates of NOx, CO, $PM_{10}/PM_{2.5}$, and VOM (as NMHC) from the affected engine in grams/hp-hour;

B. The maximum emission rates for NOx + NMHC, CO, and PM from the affected engine in grams/kW-hr output; and

C. The maximum emission rates for NOx, CO, VOM, PM, $PM_{10}/PM_{2.5}$, SO_2, and GHG (as CO_2e) from the affected engine in pounds per hour.

ii. Records of the actual emissions of NOx, CO, VOM, PM, $PM_{10}/PM_{2.5}$, SO_2, and GHG (as CO_2e) for the affected engine (tons/month and tons/year), with supporting calculations.

2.7.9 Notification and Reporting Requirements

a. The Permittee shall fulfill the applicable requirements of the NSPS, including 40 CFR 60.4214.

b. Pursuant to the Engine NESHAP, 40 CFR 63.6645(f), the Permittee shall to submit an Initial Notification that includes the information in 40 CFR 63.9(b)(2)(i) through (v) and a statement that the affected engine is stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an

emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

c. Pursuant to 35 IAC 214.305(a)(3)(C), the Permittee shall notify the Illinois EPA within 30 days after discovery of deviations from the requirements of 35 IAC 214.305(a)(2). 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.

d. For the affected engine, the Permittee shall promptly notify the Illinois EPA of deviations from the requirements of this permit for the affected engine in accordance with Condition 3.5.

Part 3: General Permit Conditions

3.1 Emission Testing Requirements

a. i. 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	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4
PM (filterable)	Method 5
$PM_{10}/PM_{2.5}$ (filterable)	Method 201A[a]
$PM_{10}/PM_{2.5}$ (condensable)	Method 202
Nitrogen Oxides (NOx)	Method 7 or 7E
Opacity	Method 9
Carbon Monoxide (CO)	Method 10
VOM and HAPs	Method 18 or 320 and 25 or 25A

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 $PM_{2.5}$.

ii. Observation of opacity shall be made in conjunction with measurements of PM, PM_{10}, and $PM_{2.5}$ emissions.

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, e.g., PM or PM_{10} emissions, pounds/hour and grains/standard cubic foot (scf) or parts per million, by volume (ppmv).

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.

3.2 Opacity Observations

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 30 minutes (five 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.

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 Reporting of Deviations

a. Reports of deviations shall include the following information:

i. Identify the deviation, with date, time, duration and description.

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

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

b. Quarterly compliance reports shall be submitted no later than 45 days after the preceding calendar quarter. This report shall also provide a listing of all deviations for which immediate or 30-day reporting was required, but need not include copies of the previously submitted information.

c. If there are no deviations during the calendar quarter, the Permittee shall still submit a compliance report, which report shall state that no deviations occurred during the reporting period.

ATTACHMENT 1

Summary of Changes in Emissions for the Project (Tons/Year)

Operation	NOx	CO	VOM	PM	PM_{10}	$PM_{2.5}$	SO_2	GHG (as CO_2e)	Indiv. HAP	Total HAP
Carbon Capture Plant										
Gas-Fired Boilers[a]	83.23	66.11	24.11	9.16	25.08	19.35	2.89	564,652	8.68	9.11
Compressor/Dehydration Systems	-	-	-[b]	-	-	-	-	1,206[c]	0.33	0.33
Piping and Piping Equipment	-	-	0.44	-	-	-	-	135.66	0.01	0.01
Circuit Breaker	-	-	-	-	-	-	-	0.02	-	-
Space Heaters	0.61	0.51	0.03	0.01	0.01	0.01	0.01	720.17	0.01	0.01
Roadways and Parking Areas	-	-	-	0.05	0.01	0.01	-	-	-	-
Emergency Engine	2.12	1.16	0.23	0.07	0.07	0.07	0.41	222.5	0.01	0.01
Subtotal	85.96	67.78	24.81	9.29	25.17	19.44	3.31	566,936	9.02	9.45
Existing Units and Operations										
North and South Ethanol Plants										
Fermentation Process	-	-	-	-	-	-	-	-[d]	-	-
South Plant Cooling Tower	-	-	-	3.23[e]	3.23[e]	3.23[e]	-	-	-	-
Boiler 3[f]	-22.68	-0.23	-2.03	-2.65	-2.65	-2.65	-0.17	-91,306	-	-
Boiler 21[f]	-27.36	-0.34	-0.61	-3.13	-3.13	-3.13	-0.15	-99,027	-	-
Subtotal	-50.05	-0.57	-2.64	-2.55	-2.55	-2.55	-0.32	-190,333	-	-
Overall Change[g]	35.91	67.21	22.17	6.74	22.62	16.89	2.99	376,603	-	-
Significant Emission Rate[h]	40	100	40	25	15	10	40	75,000	-	-
Significant?	No	No	No	No	Yes	Yes	No	Yes	-	-

Table Notes:

a. Emissions of NOx and CO represent the emissions of the three gas-fired boilers following shakedown and commissioning.

b. These calculations do not address emissions of 30.22 tons/year VOM that have been carried through from the ethanol plant fermentation scrubbers. The fermentation scrubbers are permitted to emit 10.63 lb/hour (46.58 tons/year) VOM from the North and South Plants, each. Venting the scrubbers through the C/D Systems would reduce the VOM and CO_2 emissions of the North and South Ethanol Plants. The venting of these scrubbers directly to the atmosphere would remain as a mode of operation.

c. Addresses the combined CO_2 emissions from normal operation and blowdown events, i.e., 1,060.40 tons/year CO_2 from the vents on the units comprising the C/D Systems, and 145.72 tons/year CO_2 from blowdown events.

d. There would be potential reductions in GHG (as CO_2e) emissions of approximately 1,653,467 tons/year from the North and South Ethanol Plants that would result from the capture and sequestration of GHG. In particular, information provided in the application indicates that potential GHG emissions from the North and South Ethanol Plant would be reduced by approximately 1.5 million metric tons (1.65 million tons) of GHG (as CO_2e).

e. Represents the increase in emissions that would result from increased utilization of the South Plant cooling tower system. As provided in the application, the South Plant cooling tower has the capacity to support the operation of the C/D Systems. The increases in PM, PM_{10}, and $PM_{2.5}$ emissions were determined based on the C/D Systems requiring 708,000 gallons/hour of recirculated water. As provided by Condition 2.11.4(c)(ii) of Construction Permit 17040028, the recirculation rate of the South Plant cooling tower is limited to 7,000,000 gallons/hour.

f. Represents the baseline actual emissions of Boilers 3 and 21, as determined from the period of August 2019 through July 2021, which addresses all pollutants. Baseline actual emissions of NOx were determined from data measured by CEMS on Boilers 3 and 21 during the baseline period. Emissions of CO, PM, PM_{10}, $PM_{2.5}$, SO_2 and VOM were calculated using operational records during the baseline period and emission factors obtained from stack testing. Baseline actual emissions of PM_{10} and $PM_{2.5}$ include both filterable and condensable particulates. Boilers 3 and 21 would be permanently shut down as part of this project.

g. The overall change may not match the sums due to rounding.

h. Increases in emissions from this project are compared against the significant emission rates defined at 35 IAC 204.660. This is because the carbon capture plant would be considered a single source with the existing Ethanol Complex and the CHP Plant, which is addressed as a major stationary source for purposes of 35 IAC 204.

STATE OF ILLINOIS
ENVIRONMENTAL PROTECTION AGENCY
BUREAU OF AIR
P. O. BOX 19276
SPRINGFIELD, ILLINOIS 62794-9276

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

July 1, 1985

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act, and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Agency and a supplemental written permit issued.

4. The Permittee shall allow any duly authorized agent of the Agency upon the presentation of credentials, at reasonable times:

   a. to enter the Permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

   b. to have access to and copy any records required to be kept under the terms and conditions of this permit,

   c. to inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

   d. to obtain and remove samples of any discharge or emission of pollutants, and

   e. to enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

   a. shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,

   b. does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities,

   c. does not release the Permittee from compliance with the other applicable statues and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations,

   d. does not take into consideration or attest to the structural stability of any units or parts of the project, and

e. in no manner implies or suggests that the Agency (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Agency before the equipment covered by this permit is placed into operation.

b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Agency may file a complaint with the Board for modification, suspension or revocation of a permit:

a. upon discovery that the permit application contained misrepresentations, misinformation or false statements or that all relevant facts were not disclosed, or

b. upon finding that any standard or special conditions have been violated, or

c. upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.