Statement of Basis

Minor Air Quality Operating Permit and Air Quality Construction Permit Modification

Chevron Mill Valley RNG LLC
Milbank, South Dakota

South Dakota Department of Agriculture and Natural Resources

Table of Contents

Table of Contents

Page

1.0 Background

Chevron Mill Valley RNG, LLC, (Chevron Mill Valley) formally known as Brightmark Mill Valley RNG LLC, is a renewable natural gas facility located in Millbank, South Dakota that utilizes dairy manure to produce renewable natural gas. The North American Industrial Classification System (NAICS) code is 325120 – Biogases, Industrial (i.e., compressed, liquefied, solid), Manufacturing.

On March 14, 2022, the Department of Agriculture and Natural Resources (DANR) issued an air quality construction permit to Chevron Mill Valley.

On June 10, 2024, DANR modified the air quality construction permit to add another flare, replace a boiler, update digester size, and change permitted hydrogen sulfide limit on the digester gas.

On May 1, 2025, DANR received a minor air quality operating application from Chevron Mill Valley. The application was considered complete October 27, 2025.

1.1 Existing Equipment

Table 1-1 provides a list of the units currently listed in from the air quality construction permit modification issued on June 10, 2024.

Table 1-1 – Description of Permitted Units, Operations, and Processes

Unit	Description	Maximum Operating Rate	Control Device
#1	2022 Shand & Jurs model 97300 flare fired with digester gas	9.8 million Btu per hour	Not applicable
#2	2023 Hero model G20MP-SR flare fired with digester gas	10.6 million Btu per hour	Not applicable

1.2 Proposed Changes

On May 1, 2025, DANR received a minor air quality operating application from Chevron Mill Valley. Since the previous permit modification, Chevron Mill Valley's current permit contains outdated calculations and permit reporting conditions. DANR will do the review for the minor air quality operating permit and for a modification to air quality construction permit #28.000117-01C at the same time for administrative ease.

1.3 Other Emission Activities

Table 1-2 provides a description of other emission activities located at Chevron Mill Valley.

Table 1-2 – Description of Other Units, Operations, and Processes

Unit	Description	Maximum Operating Rate	Control Device
Boiler #3	Cleaver Brooks model CFC-E boiler fired with natural gas	3.5 million Btu per hour	Not applicable
Digester #1	Anerobic digesters	3,200,000 gallons capacity	Not applicable
BUU #1	Biogas upgrading unit	315 standard cubic feet per minute	Not applicable

2.0 New Source Performance Standards

DANR reviewed the New Source Performance Standards in 40 CFR Part 60 and determined the following standards may be applicable to Chevron Mill Valley.

2.1 Standards Applicable to Boilers – Subparts D, Da, Db, and Dc

There are four New Source Performance Standards for fossil fuel-fired steam generators. The four standards are applicable to the following steam generators:

1. **40 CFR Part 60, Subpart D:** applicable to a steam generator with a maximum operating rate of 250 million Btu per hour or more and commenced construction after August 17, 1971;
2. **40 CFR Part 60, Subpart Da:** Standards for Electric Utility Steam Generating Units. This subpart is applicable to each utility generating unit that is capable of combusting more than 73 megawatts (250 million Btu per hour) heat input of fossil fuel (either alone or in combination with any other fuel) that commenced construction, modification, or reconstruction after September 18, 1978;
3. **40 CFR Part 60, Subpart Db**: applicable to a steam generator with a maximum operating rate of 100 million Btu per hour or more and commenced construction after June 19, 1984; and
4. **40 CFR Part 60, Subpart Dc**: applicable to a steam generator with a minimum design heat input capacity equal to or greater than 10 million Btu per hour but less than or equal to 100 million Btu per hour and commenced construction after June 9, 1989.

Chevon's operations include one boiler, fueled with natural gas. The boiler, Boiler #3, has a maximum operating rate of 3.5 million Btu per hour, which is less than 10 million Btu per hour. Therefore, Boiler #3 is not applicable to Subparts D, Da, Db, or Dc.

2.2 Standards Applicable to Onshore Natural Gas Plants – Subpart KKK

The provisions of 40 CFR Part 60 Subpart KKK apply to affected facilities in onshore natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. A natural gas processing plant (gas plant)

means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

Chevron Mill Valley's facility does not meet the definition of a natural gas processing plant under this subpart. Additionally, construction of the facility commenced after August 23, 2011. Therefore, this subpart is not applicable to Chevron Mill Valley.

2.3 Standards Applicable to Onshore Natural Gas Plants – Subpart LLL

The provisions of 40 CFR Part 60 Subpart LLL are applicable to the following affected facilities that process natural gas: each sweetening unit, and each sweetening unit followed by a sulfur recovery unit which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

The provisions of this subpart are not applicable to Chevron Mill Valley because construction of the facility commenced after August 23, 2011.

2.4 Standards for Crude Oil and Natural Gas Facilities – Subpart OOOO

The provisions of 40 CFR Part 60 Subpart OOOO establish emission standards and compliance schedules for the control of volatile organic compound (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, reconstruction, or modification after August 23, 2011, and on or before September 18, 2015.

The provisions of this subpart are not applicable to Chevron Mill Valley because construction of the facility commenced after September 18, 2015.

2.5 Standards for Crude Oil and Natural Gas Facilities – Subpart OOOOa

The provisions of 40 CFR Part 60 Subpart OOOOa establish emission standards and compliance schedules for the control of volatile organic compound (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, reconstruction, or modification after September 18, 2015. An applicable facility is an onshore facility that is located within the Crude Oil and Natural Gas Production source category as defined in section 60.5397a. The definition given for a Natural Gas Production source category is "Natural gas production and processing, which includes the well and extends to, but does not include, the point of custody transfer to the natural gas transmission and storage segment."

The operations for the facility do not include a natural gas well. The provisions of this subpart are not applicable to Chevron Mill Valley because the operations at the facility do not meet the definition of a Natural Gas Production source category.

2.6 Other Applicable New Source Performance Standards

DANR reviewed the other New Source Performance Standards and determined there are no other standards applicable to Chevron Mill Valley facility at this time.

3.0 New Source Review

The Administrative Rules of South Dakota (ARSD) 74:36:10:01 state that New Source Review regulations apply to areas of the state which are designated as nonattainment pursuant to the Clean Air Act for any pollutant regulated under the Clean Air Act. Chevron Mill Valley's facility is located near Millbank, South Dakota, which is in attainment or unclassifiable for all the pollutants regulated under the Clean Air Act. Therefore, Chevron Mill Valley is not subject to a New Source Review.

4.0 Prevention of Significant Deterioration

A Prevention of Significant Deterioration review applies to new major stationary sources and major modifications to existing major stationary sources in areas designated as attainment under Section 107 of the Clean Air Act for any regulated air pollutant. The following is a list of regulated air pollutants under the Prevention of Significant Deterioration program:

1. Total suspended particulate (PM);
2. Particulate with a diameter less than or equal to 10 microns (PM10);
3. Particulate with a diameter less than or equal to 2.5 microns (PM2.5);
4. Sulfur dioxide (SO_2);
5. Nitrogen oxides (NO_x);
6. Carbon monoxide (CO);
7. Ozone – measured as volatile organic compounds (VOCs);
8. Lead;
9. Fluorides;
10. Sulfuric acid mist;
11. Hydrogen sulfide;
12. Reduced sulfur compounds;
13. Total reduced sulfur; and
14. Greenhouse gases (carbon dioxide, methane, nitrous oxide, etc.).

If the source is considered one of the 28 named Prevention of Significant Deterioration source categories listed in Section 169 of the federal Clean Air Act, the major source threshold is 100 tons per year of any regulated air pollutant, except for greenhouse gases. The major source threshold for all other sources is 250 tons per year of any regulated air pollutant, except for greenhouse gases. Chevron Mill Valley is not one of the 28 named Prevention of Significant Deterioration source categories; therefore, the major source threshold for pollutants is 250 tons per year. A facility must trigger one of the major source thresholds for another regulated pollutant before greenhouse gas emissions can be considered under the Prevention of Significant Deterioration permitting program. This applies to both new Prevention of Significant Deterioration program sources as well as major source modifications.

4.1 Potential Emissions

DANR uses stack test results to determine air emissions whenever stack test data are available from the source or a similar source. When stack test results are not available, DANR relies on manufacturing data, material balance, EPA's Compilation of Air Pollutant Emission Factors (AP-42, Fifth Edition, Volume 1), information submitted in the application, or other methods to determine potential air emissions. Potential emissions for each applicable pollutant are calculated by assuming the unit operates every day of the year at the maximum design capacity (8,760 hours per year).

4.1.1 Potential Emissions – Anaerobic Digesters

The facility includes the operation of anaerobic digesters. The estimated maximum biogas generation rate is approximately 315 standard cubic feet per minute, which is 165,564,000 standard cubic feet per year. Based on the current available information, the digesters do not produce particulate matter, sulfur dioxide, nitrogen oxide, volatile organic compounds, and carbon monoxide. Therefore, these emissions will not be evaluated for the digesters. The digesters do produce methane, which is a greenhouse gas. At this point, DANR will not evaluate greenhouse gases unless a Prevention of Significant Deterioration review for another pollutant is triggered first. The digesters do produce hydrogen sulfide, which could trigger a Prevention of Significant Deterioration review. Chevron Mill Valley's application indicates the worst-case scenario sulfur content of the biogas produced by the digesters would be 5,000 parts per million. Equation 4.1 was used to determine the potential hydrogen sulfide emissions from the digesters without any controls (e.g., flares).

Equation 4.1 – Digester Hydrogen Sulfide Emissions

$$\text{Potential Emissions}\left[\frac{\text{tons}}{\text{year}}\right] = \frac{GFlow\ x\ F_{H_2S} \times CF_{AP42}}{2{,}000}$$

Where:

- GFlow = biogas generation rate in cubic feet per year (e.g., 165,564,000 standard cubic feet per year)
- F_{H2S} = the hydrogen sulfide content of the fuel (i.e., 5,000 parts per million or 0.0050);
- CF_{AP42} = AP-42 conversion factor (parts per million to pounds per million cubic feet); = 34.08 pounds per pound-mole (molecular weight of H_2S) ÷ 385.1 million cubic feet per pound-mole (derived from ideal gas law at standard temperature and pressure) or 0.0885 pounds H_2S per cubic feet H_2S;
- 2,000 = pounds per ton.

Table 4-1 lists the potential regulated emissions from the digesters without controls.

Table 4-1 – Potential Emissions from Digesters (tons per year)

	H_2S
Digesters	**36.6**

4.1.2 Potential Emissions – Boiler

Chevron Mill Valley's boiler is fueled by natural gas with a maximum operating rate of 3.5 million Btus per hour. The emission factors for natural gas combustion are derived from AP-42, 1.4, Tables 1.4-1 and 1.4-2, April 2026, and are displayed in Table 4-2.

Table 4-2 – Emission Factors Natural Gas Combustion

	TSP	PM_{10}	$PM_{2.5}$	SO_2	NOx	CO	VOC
Pounds per million cubic feet[1]	7.6	7.6	7.6	0.6	100	84	5.5
Pounds per million Btu	0.0075	0.0075	0.0075	0.0006	0.098	0.082	0.0054

[1] – To convert from pounds per million cubic feet to pounds per million Btu, divide by 1,020.

Potential emissions from the boiler are calculated using Equation 4.2, the emission factors from Table 4-2, and the heat input of the boiler. The results are shown in Table 4-3.

Equation 4.2 – Potential Emissions

$$\text{Potential Emissions}\left[\frac{\text{tons}}{\text{year}}\right] = \frac{\text{Emission Factor}\left[\frac{\text{pounds}}{\text{MMBtu}}\right] \times \text{Heat Input}\left[\frac{\text{MMBtu}}{\text{hour}}\right] \times 8{,}760\left[\frac{\text{hours}}{\text{year}}\right]}{2{,}000\left[\frac{\text{pounds}}{\text{ton}}\right]}$$

Table 4-3 – Potential Emissions from Boiler (tons per year)

Unit	TSP	PM_{10}	$PM_{2.5}$	SO_2	NOx	CO	VOC
Boiler #3	**0.11**	**0.11**	**0.11**	**0.01**	**1.50**	**1.26**	**0.08**

4.1.3 Potential Emissions – RNG Flare

Chevron Mill Valley operates two flares. One flare is used to only combust raw biogas if the biogas upgrading unit or pipeline would be down. The other flare is used to combust scrubbed biogas that has already been through the biogas upgrading unit. The renewable natural gas treatment system consists of membranes to permeate carbon dioxide and sulfur from the gas and filters, compressors, and coolers to remove moisture. Chevron Mill Valley estimates that of the 315 standard cubic feet per minute of biogas (165.56 million standard cubic feet per year) sent to the biogas upgrading unit under this scenario, 45% (74.5 standard cubic feet per year) is emitted as "tail gas". The tail gas is composed of the following: 97.9% carbon dioxide, 2.0% methane, 0.0% nitrogen, 0.0% oxygen, and 0.2% water.

Potential emissions for the RNG flare, Unit #2, are based on the remaining 91.1 million standard cubic feet per year of gas after the venting of the tail gas. Since this flare burns off-spec renewable natural gas, the emission factors for natural gas combustion will be used. The emission factors for natural gas combustion are derived from AP-42, 1.4, Tables 1.4-1 and 1.4-2, April 2026, and are displayed in Table 4-2.

Potential emissions from the RNG Flare, Unit #2, are calculated using Equation 4.3, the emission factors from Table 4-2, and the gas flowrate of 91.1 million standard cubic feet per year and the conversion factor of 2,000 pounds per ton. The results are shown in Table 4-4.

Equation 4.3 – Potential Emissions from Flares

$$\text{Potential Emissions}\left[\frac{\text{tons}}{\text{year}}\right] = \frac{\text{Biogas Production}\left[\frac{\text{MMscf}}{\text{year}}\right] \times \text{Emission Factor}\left[\frac{\text{pounds}}{\text{MMscf}}\right]}{2{,}000\left[\frac{\text{pounds}}{\text{ton}}\right]}$$

Table 4-4 – Potential Emissions from RNG Flare (tons per year)

Unit	TSP	PM_{10}	$PM_{2.5}$	SO_2	NOx	CO	VOC
RNG Flare	0.35	0.35	0.35	0.03	4.56	3.83	0.25

4.1.4 Potential Emissions – Biogas Flare

Potential emissions for the raw biogas flare, Unit #1, is based on the operating scenario where the biogas upgrading unit is not operational and that flare burns all the biogas produced by the digesters 315 standard cubic feet per minute (165.56 standard cubic feet per year).

AP-42 does not have emission factors for combusting digester gas. Emissions from the flare for particulate matter, nitrogen oxides, carbon monoxide, and volatile organic compounds are based on emission factors in AP-42, Chapter 2.4 – Municipal Solid Waste Landfills, Table 2.4-5, May 2025. The emission factors are shown in Table 4-5.

Table 4-5 – Emission Factors for Flares

	TSP	PM_{10}	$PM_{2.5}$	NOx	CO	VOC
AP-42 (pounds per million dry standard cubic feet of Methane)	17	17	17	38	58	4.1

Sulfur dioxide emissions from biogas combustion depend on the sulfur content of the fuel. However, Chevron Mill Valley provided a worst-case scenario sulfur content estimate in the application (i.e., 5,000 parts per million).

DANR used Equation 4.4 and the estimated sulfur content to develop a sulfur dioxide emission factor based on the application of the ideal gas law under standard conditions and the assumption that any sulfur in the biogas is in the form of hydrogen sulfide and that 100 percent of that sulfur converts to sulfur dioxide during combustion. The emission factor is shown in Table 4-7.

Equation 4.4 – Sulfur Dioxide Emission Factor Derivation for Flares

$$Emission\ Factor\left[\frac{lbs\ SO_2}{MMscf}\right] = \frac{F_{H_2S} \times CF_{AP42} \times WF_{S/H_2S}}{WF_{S/SO_2}}$$

Where:

- F_{H2S} = the hydrogen sulfide content of the fuel (i.e., 5,000 parts per million);
- CF_{AP42} = AP-42 conversion factor (parts per million to pounds per million cubic feet);
  = 34.08 pounds per pound-mole (molecular weight of H_2S) ÷ 385.1 million cubic feet per pound-mole (derived from ideal gas law at standard temperature and pressure);
  = 0.088 pounds per million cubic feet, per parts per million

- $WF_{S/H2S}$ = weight fraction of sulfur in hydrogen sulfide (i.e., 0.94 pounds of sulfur per pounds of hydrogen sulfide);
- $WF_{S/SO2}$ = weight fraction of sulfur in sulfur dioxide (i.e., 0.50 pounds of sulfur per pounds of sulfur dioxide);

Table 4-6 – Sulfur Dioxide Emission Factor

	SO_2
Pounds per million standard cubic feet	827

Potential emissions are calculated using Equation 4.3, the biogas production of 165.56 million standard cubic feet per year, the emission factors from Tables 4-5 and 4-6, and the conversion factor of 2,000 pounds per ton. The results are shown in Table 4-7.

Table 4-7 – Potential Emissions from Biogas Flare (tons per year)

Unit	TSP	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC
Biogas Flare	1.41	1.41	1.41	68.48	3.15	4.80	0.34

4.1.5 Summary of Potential Emissions

Table 4-8 summarizes the facility-wide potential emissions.

Table 4-8 – Facility-wide Potential Emissions (tons per year)

Unit	TSP	PM_{10}	$PM_{2.5}$	SO_2	NOx	CO	VOC	H_2S
Digesters	-	-	-	-	-	-	-	36.6
Boiler #3	0.11	0.11	0.11	0.01	1.50	1.26	0.08	-
RNG Flare	0.35	0.35	0.35	0.03	4.56	3.83	0.25	-
Biogas Flare	1.41	1.41	1.41	68.48	3.15	4.80	0.34	-
Total[1]	**2**	**2**	**2**	**68**	**6**	**6**	**0**	**37**

[1] – The highest potential emissions for each criteria pollutant from each flare was used for the facility-wide total.

4.2 Significant Deterioration Summary

Based on Table 4-8, Chevron Mill Valley's potential emissions are less than 250 tons per year. Therefore, Chevron Mill Valley is considered a minor source and is not applicable to the Prevention of Significant Deterioration program. As Chevron Mill Valley is not applicable to the Prevention of Significant Deterioration program, a review for greenhouse gas emissions is not warranted or required.

5.0 National Emissions Standards for Hazardous Air Pollutants

DANR reviewed the National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 61 and determined there are no standards applicable to Chevron Mill Valley's renewable natural gas facility.

6.0 Maximum Achievable Control Technology Standards

The federal Maximum Achievable Control Technology Standards are applicable to both major and area sources of hazardous air pollutants. A major source of hazardous air pollutants is defined as having the potential to emit 10 tons or more per year of a single hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An area source is a source that is not a major source of hazardous air pollutants.

6.1 Potential Hazardous Air Pollutant Emissions

DANR uses stack test results to determine air emissions whenever stack test data is available from the source or a similar source. When stack test results are not available, DANR relies on manufacturing data, material balance, EPA's Compilation of Air Pollutant Emission Factors (AP-42, Fifth Edition, Volume 1) document, the applicant's application, or other methods to determine potential air emissions.

6.1.1 Potential Hazardous Air Pollutant Emissions – Anaerobic Digester

Based on the current available information, the digesters do not produce hazardous air pollutants. Therefore, no hazardous air pollutant emission calculations will be conducted for the digesters.

6.1.2 Potential Hazardous Air Pollutant Emissions - Boiler

Chevron Mill Valley's boiler #3 is fueled by natural gas. The hazardous air pollutant emission factor for natural gas combustion is derived from AP-42, 1.4, Table 1.4-3, April 2026, and is displayed in Table 6-1.

Table 6-1 – Emission Factors Natural Gas Combustion

	HAPs
Pounds per million cubic feet[1]	1.888
Pounds per million Btu	0.00185

[1] – To convert from pounds per million gallons to pounds per million Btu, divide by 1,020.

Potential hazardous air pollutant emissions from the boiler are calculated using Equation 4.2, the hazardous air pollutant emission factor from Table 6-1, and the heat inputs of the boiler. The results are shown in Table 6-2.

Table 6-2 – Potential Emissions from Boiler (tons per year)

Description	**HAPs**
Boiler #3	0.03

6.1.3 Potential Hazardous Air Pollutant Emissions – RNG Flare

As mentioned above, the RNG flare only burns off-spec gas. Potential emissions for the RNG flare are based on the remaining 91.1 million standard cubic feet per year of gas after the venting of the tail gas. Since this flare will only burn off-spec renewable natural gas, the hazardous air

pollutant emission factor for natural gas combustion will be used. The hazardous air pollutant emission factor for natural gas combustion are derived from AP-42, 1.4, Table 1.4-3, April 2026, and is displayed in Table 6-1.
Potential hazardous air pollutant emissions from the RNG Flare are calculated using Equation 4.3, the hazardous air pollutant emission factor from Table 6-1, and the gas flowrate. The results are shown in Table 6-3.

Table 6-3 – Potential Emissions from RNG Flare (tons per year)

Description	HAPs
RNG Flare	0.09

6.1.4 Potential Hazardous Air Pollutant Emissions – Biogas Flare

Chevron Mill Valley operates a flare to control biogas emissions during the processing. Because AP-42 does not provide hazardous air pollutant emission factors for biogas combustion, DANR will use the hazardous air pollutant emission factor for natural gas combustion. The hazardous air pollutant emission factor for natural gas combustion is derived from AP-42, 1.4, Table 1.4-3, April 2026, and is displayed in Table 6-4.

Table 6-4 – Emission Factors Natural Gas Combustion

	HAPs
Pounds per million cubic feet[1]	1.888

Potential hazardous air pollutant emissions from the flare are calculated using Equation 4.3, the hazardous air pollutant emission factor from Table 6-4, and a conversion factor of 2,000 pounds per ton. The result is shown in Table 6-5.

Table 6-5 – Potential Emissions from Biogas Flare (tons per year)

Description	HAPs
Biogas Flare	0.16

6.1.5 Summary of Potential Hazardous Air Pollutant Emissions

Table 6-6 provides a summary of the facility-wide potential hazardous air pollutant emissions.

Table 6-6 – Potential Emissions (tons per year)

Description	HAPs
Digesters	-
Boiler #3	0.03
RNG Flare	0.09
Biogas Flare	0.16
Total[1]	**0.19**

[1] – The highest potential emission between the flares was used for the facility-wide total.

The potential hazardous air pollutant emissions are less than 10 tons per year for a single hazardous air pollutant and 25 tons per year for a combination of hazardous air pollutants. Therefore, Chevron Mill Valley is an area source of hazardous air pollutants.

6.2 Maximum Achievable Control Technology Standards

DANR reviewed the Maximum Achievable Control Technology standards under 40 CFR Part 63 and determined the following standards may be applicable to Chevron Mill Valley.

6.2.1 Standards for Off-Site Waste and Recovery Operations – Subpart DD

The provisions of this subpart are applicable to owners and operators of plant sites that are a major source of hazardous air pollutants; and at the plant site is located one or more operations that receives off-site materials, and the operations is one off the waste management operations or recovery operations listed in the subpart. Chevron Mill Valley is considered an area source of hazardous air pollutants. Therefore, this subpart is not applicable to Chevron Mill Valley.

6.2.2 Standards Applicable to Oil and Natural Gas Production Facilities – Subpart HH

The provisions of this subpart apply to owners and operators of emission points located at oil and natural gas production facilities that meet the specified criteria. For area sources, the affected source includes each triethylene glycol (TEG) dehydration unit located at the facility that meets the criteria. Chevron Mill Valley is an area source of hazardous air pollutants. Chevron Mill Valley does not operate a TEG dehydration unit; therefore, this subpart is not applicable to Chevron Mill Valley.

6.2.3 Standards Applicable to Natural Gas Transmission and Storage – Subpart HHH

The provisions of this subpart are applicable to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants. Chevron Mill Valley is considered an area source of hazardous air pollutants. Therefore, this subpart is not applicable to Chevron Mill Valley.

6.2.4 Standards Applicable to Boilers – Subpart DDDDD

The provisions of this subpart establish national emission and operating limits for hazardous air pollutants emitted from industrial, commercial, and institutional boilers and process heaters located at a major source of hazardous air pollutant emissions. Chevron Mill Valley is considered an area source of hazardous air pollutants. Therefore, this subpart is not applicable to Chevron Mill Valley.

6.2.5 Standards Applicable to Boilers – Subpart JJJJJJ

On March 21, 2011, EPA finalized the Maximum Achievable Control Technology standard under 40 CFR Part 63, Subpart JJJJJJ. This rule applies to all new or existing industrial,

commercial, and institutional boilers located at an area source of hazardous air pollutants. An existing boiler is defined as a boiler where construction or reconstruction occurred prior to June 4, 2010.

Chevron Mill Valley has a natural gas-fired boiler constructed after 2010. In accordance with 40 CFR § 63.11195(e), a gas-fired boiler is exempt from the requirements of this subpart. A gas-fired boiler is defined as "…any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel". Gaseous fuels include natural gas. Therefore, Chevron Mill Valley is not subject to this subpart provided natural gas is the only fuel burned in the boiler.

7.0 State Requirements

7.1 Permit Type

Any source operating in South Dakota that meets the definition of a major source for any criteria pollutant is required to obtain a Title V air quality operating permit. A major source is defined as having the potential to emit greater than 100 tons per year of a criteria pollutant, greater than or equal to 10 tons per year of a single hazardous air pollutant, or greater than or equal to 25 tons per year of a combination of hazardous air pollutants, or if the source is applicable to a New Source Performance Standards or Maximum Achievable Control Technology Standards. Based on Table 4-8, Chevron Mill Valley's potential emissions are below the Title V operating permit thresholds. Therefore, a Title V air quality operating permit is not required due to criteria pollutant emissions.

Any source operating in South Dakota that meets the definition of a minor source under Administrative Rules of South Dakota (ARSD) 74:36:04:02 is required to obtain a minor air quality permit. In accordance with Administrative Rules of South Dakota (ARSD) 74:36:04:02.01, a minor source is exempt from obtaining a minor source operating permit if the source has the potential to emit 25 tons or less per year of any criteria pollutant, except lead, before the application of control equipment. Chevron Mill Valley has the potential to emit greater than 25 tons per year of a criteria air pollutant; therefore, Chevron Mill Valley is required to obtain a minor air quality operating permit.

The minor air quality operating permit and modified air quality construction permit will contain conditions that will limit biogas hydrogen sulfide content to a maximum of 5,000 parts per million. With the hydrogen sulfide limit, Chevron Mill Valley has the potential to emit less than 100 tons per year of sulfur dioxide; therefore, the sulfur dioxide emission limits will not be implemented in the minor air quality operating permit. Chevron Mill Valley will be required to test the hydrogen sulfide content of the biogas on a weekly basis, prior to combustion, to ensure the monthly average is below the sulfur content limits. Chevron Mill Valley will also be required to submit quarterly reports.

7.2 Insignificant Activities

In accordance with Administrative Rules of South Dakota (ARSD) 74:36:20:04 and 74:36:04:03, the following emission units are exempt from inclusion in the minor air quality operating permit unless the source has requested federally enforceable permit conditions related to the emission unit to avoid needing a Part 70 operating permit, Prevention of Significant Deterioration preconstruction permit, or New Source Review preconstruction permit:

1. One or more incinerators of less than 100 pounds per hour combined burning capacity that combust municipal or household waste;
2. A mobile internal combustion engine, including engines in autos, trucks, tractors, airplanes, locomotives, and boats;
3. Laboratory equipment used exclusively for chemical or physical analysis;
4. A unit that has a heat input capability of not more than 3,500,000 Btu per hour, except for units fueled with wood or coal;
5. An air conditioning or ventilating system not designed to remove air pollutants from equipment;
6. Routine housekeeping or plant upkeep activities such as painting buildings, retarring roofs, or paving parking lots;
7. A unit that has the potential to emit two tons or less per year of any criteria pollutant before the application of control equipment. However, the criteria pollutant emissions from the unit must be included in determining whether the source is a major source; and
8. A unit that has the potential to emit two tons or less per year of any hazardous air pollutant. However, the hazardous air pollutant emissions from the unit must be included in determining whether the source is a major source.

Chevron Mill Valley's boiler has the potential to emit less than two tons per year of any criteria air pollutant; therefore, the boiler is exempt from being a permitted unit.

The project includes anaerobic digesters. The digesters only emit hydrogen sulfide. Hydrogen sulfide potential emissions are below 100 tons per year; therefore, venting, and other non-combustion releases of hydrogen sulfide are insignificant. Since, hydrogen sulfide emissions are insignificant, the anaerobic digesters are not required to be permitted.

7.3 State Emission Limits

Administrative Rules of South Dakota 74:36:06:02 establishes state emission limits for total suspended particulate matter and sulfur dioxide. State emission limits are applicable to fuel burning and process industry units. Units classified as insignificant activities are not applicable to the state emission limits.

In accordance with Administrative Rules of South Dakota 74:36:01:01(31), a fuel burning unit means a furnace, boiler, apparatus, stack, or any of their components used in the process of burning fuel or other combustible material for the primary purposes of producing heat or power by indirect heat transfer. The flares use direct heat to burn the gas from the digesters. The flares

are not used to heat or power any other units or operations; therefore, the state emission limits for particulate matter emissions are not applicable.

Visible emissions are applicable to units that discharge into the ambient air. In accordance with Administrative Rules of South Dakota 74:36:12, a facility may not discharge into the ambient air more than 20 percent opacity for all units. Chevron Mill Valley must control the opacity at less than 20 percent for all units.

7.4 Performance Tests

In accordance with Administrative Rules of South Dakota 74:36:11:02, the Secretary may require a performance test, if necessary, to demonstrate compliance with the state's emission limits. The minor air quality operating permit will contain a hydrogen sulfide concentration limit. Compliance with this limit will be based on periodic hydrogen sulfide content testing of the biogas being routed out of the digester. Therefore, a performance test will not be required. However, permit conditions will be included in the permit that will allow DANR to require a performance test if DANR believes a performance test in necessary in the future to demonstrate compliance.

7.5 Standards for Flares

Typically, DANR includes flare requirements, from 40 CFR Part 60.18(b), in the permit. However, the flare requirements are more related to flares used specifically as control devices. The flares at Chevron Mill Valley's facility will be used to burn biogas and not for controlling a process in order to meet a permit limit. Chevron Mill Valley will not have a limit based specifically on the flares operating. Therefore, DANR will not include the flare requirements in the permit.

8.0 Recommendation

Chevron Mill Valley is required to operate the renewable natural gas facility within the requirements stipulated in the following regulations:

1. ARSD 74:36:04 – Operating Permits for Minor Sources;
2. ARSD 74:36:06 – Regulated Air Pollutant Emissions;
3. ARSD 74:36:11 – Performance Testing; and
4. ARSD 74:36:12 – Control of Visible Emissions;
5. ARSD 74:36:20 – Construction Permits for New Sources or Modifications.

Based on the information submitted in the air quality permit application, DANR recommends approval of a minor air quality operating permit and a modified air quality construction permit for Chevron Mill Valley's renewable natural gas facility near Millbank, South Dakota. The proposed permit changes to air quality construction permit #28.000117-01C can be seen in Appendix A. Questions regarding this permit review should be directed to Thang Nguyen, Engineer I, Department of Agriculture and Natural Resources – Air Quality Program.

Appendix A
Modifications to Air Quality Construction Permit #28.000117-01C

The following changes to the existing permit represent changes that meet the definition of a permit modification. Additions to the existing permit are represented in blue, bold, and underlined and deletions are represented in red with overstrikes. In the case where permit conditions are deleted or added between permit conditions, the permit conditions will be renumbered appropriately when the permit is issued.

Under the South Dakota Air Pollution Control Regulations

Pursuant to Chapter 34A-1-21 of the South Dakota Codified Laws and the Air Pollution Control Regulations of the State of South Dakota and in reliance on statements made by the owner designated below, a permit to construct and operate is hereby issued by the Secretary of the Department of Agriculture and Natural Resources. This permit authorizes such owner to construct and operate the permitted unit(s) at the location designated below and under the listed conditions.

A. Owner

1. Company Name and Mailing Address

~~Brightmark Mill Valley~~ **Chevron Mill Valley** RNG LLC
~~1725 Montgomery St. FL3~~ **1500 Smith Street,**
~~San Francisco, CA 94111~~ **Houston, TX 77002**

2. Actual Source Location if Different from Above

15161 476th Avenue
Milbank, SD 57252

3. Permit Contact

~~Lillian Burns~~ **Al Garcia, Senior Environment and Regulatory Specialist**
~~(650) 420-7849~~ **860-883-7717**

4. Facility Contact

~~Lillian Burns~~ **John Kenney, Operations Manager,**
~~(650) 420-7849~~ **970-629-1637**

5. Responsible Official

~~Joseph Atkinson, Chief Operation Officer~~ **Sebastian De La Rosa, Operations Maintenance Manager,**

~~(650) 434-0537~~ **432-269-7253**

B. Permit Revisions

June 10, 2024 – modification to update contacts, limits for sulfur dioxide, and the compliance demonstration for the short-term sulfur limit.
April 28, 2026 – modification to update reporting terms and limits and contact updates

C. Description of Construction Activity

Biogas production facility.

1.0 Standard Conditions

1.1 Construction and operation of source

In accordance with Administrative Rules of South Dakota (ARSD) 74:36:20:15(9), the owner or operator shall construct and operate the units, controls, and processes as described in Table 1-1 in accordance with the statements, representations, and supporting data contained in the complete permit application received June 7, 2021, ~~and~~ January 8, 2024, **and May 1, 2025**, unless modified by the conditions of this permit. Except as otherwise provided herein, the control equipment in Table 1-1 shall be operated at all times in accordance with the manufacturer's specification and in a manner that achieves compliance with the conditions of this permit. The application consists of the application forms, supporting data, and supplementary correspondence. If the owner or operator becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in an application, such information shall be promptly submitted.

Table 1-1 – Description of Permitted Units, Operations, and Processes

Unit	Description	Maximum Operating Rate	Control Device
#1	2022Shand & Jurs model 97300 flare fired with digester gas	9.8 million Btu per hour	Not applicable
#2	2023 Hero model G20MP-SR flare fired with digester gas	10.6 million Btu per hour	Not applicable

4.0 Recordkeeping and Reporting

4.1 Recordkeeping and reporting

In accordance with ARSD 74:36:20:15(10), the owner or operator shall maintain all monitoring data, records, reports, and pertinent information specified by this permit for five years from the date of sample, measurement, report, or application unless otherwise specified in this permit. The records shall be maintained on site for the first two years and may be maintained off site for the last three years. All records must be made available to the Secretary for inspection. ~~All~~

~~notifications and reports shall be submitted to the Secretary using one of the following two notification methods:~~

If the owner or operator chooses to submit the notification or report to the Secretary by mail, the owner or operator shall use the following mailing address, and the postmarked date is considered the date the notification or report was submitted:

Notification Method 1 – Mailing Address

South Dakota Department of Agriculture and Natural Resources
PMB 2020, Air Quality Program
523 E. Capitol, Joe Foss Building
Pierre, SD 57501-3182

Or

If the owner or operator chooses to submit the notification or report to the Secretary by mail, the owner or operator shall use the following mailing address, and the postmarked date is considered the date the notification or report was submitted:

Notification Method 2 – Email Address

AirQualityReporting@state.sd.us

Each notification and report shall contain the information required in this permit, the signature of the responsible official or duly authorized representative as outlined in permit condition 4.6 and the certification statement in permit condition 4.7. If the owner or operator chooses to submit the notification and reports via email, the email must contain an acrobat copy (PDF) of the notification or report. The acrobat copy must contain the required information, signature, and certification statement. If a notification or report is required to be notarized, the notification or report may not be submitted by email.

4.4 Monthly records

In accordance with ARSD 74:36:20:15(10), the owner or operator shall calculate and record the following amounts each month:

1. The amount of sulfur dioxide, in tons, emitted into the ambient air from the permitted units during the month. A 12-month rolling total shall be calculated every month using that months' value and the previous 11 months' values. The amount of sulfur dioxide emitted to the ambient air from permitted units shall be calculated using ~~sulfur content of raw biogas, formulas, emission factors, and methods described in the statement of basis;~~ **a mass balance equation incorporating the sulfur content of biogas determined by the records in permit conditions 4.4(4);**
2. The ~~amount~~**volume** of biogas combusted in the flares, Units #1 and #2, during the month. A 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values;

3. The amount of biogas produced during the month. A 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values; ~~and~~
4. Sulfur content of biogas as determined by sulfur content testing as described in permit condition 7.2; **and**
5. **Instances where the facility is not operating, and a sulfur content reading is not taken.**

4.5 Quarterly reporting

In accordance with ARSD 74:36:20:15(10), the owner or operator shall submit ~~a~~ quarterly report**s** to the Secretary ~~by the end of each calendar quarter~~. The quarterly report shall contain the following information:

1. Name of facility, permit number, reference to this permit condition, identifying the submittal as a quarterly report, and calendar dates covered in the reporting period;
2. The amount of sulfur dioxide emissions, in tons, emitted into the ambient air from the permitted units during each month and the 12-month rolling total for each month in the reporting period;
3. The ~~amount~~ **volume** of biogas combusted in the flares, Units #1 and #2, ~~during~~ each month and the 12-month rolling total for each month in the reporting period;
4. ~~Quarterly~~**Monthly** average sulfur content of biogas as determined by **every weekly** ~~the monthly~~ sulfur content test~~ing~~ **taken during the calendar month** as described in permit condition 7.2; ~~and~~
5. **Instances where the facility is not operating, and a sulfur content reading is not taken; and**
6. The amount of biogas produced during each month and the 12-month rolling total for each month in the reporting period.

~~Quarterly reports are required to be submitted until an air quality operating permit is issued.~~ The quarterly report must be postmarked no later than 30 days after the end of the reporting period (i.e., April 30th, July 30th, October 30th, and January 30th).

4.8 Reporting permit violations

In accordance with ARSD 74:36:20:15(10), the owner or operator shall report all permit violations. A permit violation should be reported as soon as possible, but no later than the first business day following the day the violation was discovered. The permit violation may be reported by telephone to the South Dakota Department of Agriculture and Natural Resources at (605) 773-3151 or by FAX at (605) 773-~~4068~~**5286**.

A written report shall be submitted within five days of discovering the permit violation. Upon prior approval from the Secretary, the submittal deadline for the written report may be extended up to 30 days. The written report shall contain:

1. A description of the permit violation and its cause(s);
2. The duration of the permit violation, including exact dates and times; and
3. The steps taken or planned to reduce, eliminate, and prevent reoccurrence of the permit violation.

6.0 Performance Tests

6.1 Performance test may be required

In accordance with ARSD 74:36:11:02, the Secretary may request a performance test **during the term of this permit**. A performance test shall be conducted while operating the unit at or greater than 90 percent of its maximum design capacity, unless otherwise specified by the Secretary. A performance test ~~that is~~ conducted while operating ~~at~~ less than 90 percent of its maximum design capacity will result in the operation being limited to the percent achieved during the performance test. The Secretary has the discretion to extend the deadline for completion of ~~the~~ performance test required by the Secretary if circumstances reasonably warrant but will not extend the deadline past a federally required performance test deadline.

6.2 Test methods and procedures

In accordance with ARSD 74:36:11:01, the owner or operator shall conduct the performance test in accordance with **40 CFR. § 60.17,** 40 CFR Part 60, Appendix A, 40 CFR Part 63, Appendix A, and 40 CFR Part 51, Appendix M. The Secretary may approve an alternative method if a performance test specified in **40 CFR. § 60.17,** 40 CFR Part 60, Appendix A, 40 CFR Part 63, Appendix A, and 40 CFR Part 51, Appendix M is not **federally** applicable or **federally** required.

6.4 Submittal of test plan

In accordance with ARSD 74:36:11:01, the owner or operator shall submit the proposed testing procedures to the Secretary at least 30 days prior to any performance test. The Secretary will notify the owner or operator if the proposed test procedures are approved or denied. If the proposed test procedures are denied, the Secretary will provide written notification ~~that outlines~~ **outlining** what needs to be completed for approval.

6.6 Performance test report

In accordance with ARSD 74:36:20:15(10), the owner or operator shall submit a performance test report to the Secretary within 60 days after completing the performance test or by a date designated by the Secretary. The performance test report shall contain the following information:

1. **A brief** description of the process and the air pollution control system being tested;
2. Sampling location description(s);
3. A description of sampling and analytical procedures and any modifications to standard procedures;
4. Test results ~~expressed in units consistent with the applicable emission limit~~ **represented in the same terminology as the permit limits**;
5. Quality assurance procedures and results;
6. Records of ~~unit's~~ operating conditions during the test ~~(e.g., operating rate, fuel type)~~ **necessary for demonstrating compliance with the permit limits, preparation of standards, and calibration procedures**;
7. Raw data sheets for field sampling and field and laboratory analyses;
8. Documentation of calculations;
9. All data recorded and used to establish parameters for compliance monitoring; and
10. Any other information required by the test method.

7.0 Hydrogen Sulfide Compliance Demonstration

7.2 Monitoring sulfur content of biogas ~~quarterly~~Monthly

~~In accordance with ARSD 74:36:20:15(10), the owner or operator shall collect samples of the biogas produced during the quarter to determine the average sulfur content. Samples shall be collected on a monthly or more frequent basis to calculate the quarterly average sulfur content. If the flare is not operated during a calendar month, then a sulfur content sample will not be required that month. The quarterly average is to be calculated using every monthly sulfur content average takes while the flare was in operation. The samples shall be collected at a point between the anaerobic digester~~ **In accordance with ARSD 74:36:20:15(10), the owner or operator shall collect samples of the biogas prior to combustion during the calendar month to determine the average sulfur content. Samples shall be collected on a weekly or more frequent basis to calculate the monthly average sulfur content. If the facility is not operated during a week, then a sulfur content sample will not be required that week. The monthly average is to be calculated using each sulfur content sample taken during the month while the facility was in operation. The samples shall be collected at a point prior to combustion and be conducted by either an EPA approved test method or a portable analyzer. The samples shall be analyzed by an EPA approved test method (e.g., ASTM D5504, D4468, D1072, etc.) or a portable analyzer. If a portable analyzer is used, the portable analyzer must be maintained based on the manufacturer's instructions and certified annually. If the monthly average result from the portable analyzer indicates exceedance of the sulfur content limit in permit condition 7.1, the owner or operator shall analyze the samples using and EPA approved test method. A copy of all analyses results shall be submitted with quarterly reports.**