MEMO TO : File
Hess Tioga Gas Plant LLC (Hess)
Tioga Gas Plant
Williams County, North Dakota

FROM : Eric Yablonski
Environmental Engineer
Division of Air Quality
North Dakota Department of Environmental Quality (Department)

RE : January 9, 2024 (application), September 4, 2025 (revision), Permit to Construct (PTC) (ACP-18224 v1.0)

DATE : April 13, 2026

1. Executive Summary

Hess submitted a PTC application and revision for a PTC for Tioga Gas Plant (facility) to the Department on the dates listed above. The facility currently operates under AOP-28424 v6.0, which expires on April 3, 2027. The facility is a natural gas processing plant which consists of gas distillation, dehydration, sweetening, and compression.

As the result of an internal environmental audit (June 2023), which was conducted pursuant to North Dakota Century Code 32-40.2-01, several inconsistencies with permit representations were revealed. This Project was requested to reclassify the facility as a Prevention of Significant Deterioration (PSD) minor source and 'clean up' previous permits with one permit action, accurately capturing all recent modifications and facilitating Title V renewal (application already submitted at the time of permit review). There are no proposed equipment or operational changes associated with this permit action, but previously unrepresented emission units (EUs) are included in this permit (see Section 3).

In January of 2020, Hess moved their existing continuous emission rate monitoring system to the incinerator vent stack (Emission Point S-302) and enabled a bypass of the Claus Sulfur Recovery Unit (SRU); this was due to low sulfur content of inlet gas that prevented the SRU from operating within specification. Following this trend, recent reported SO_2 emissions[1] have not exceeded 85 tpy (from consistently over 1,000 tpy), which is well below the applicable PSD major source threshold of 250 tpy.[2] Hess requested that the emission limits for SO_2 be retained since the SRU would be decommissioned in the coming year. The hourly emission rate was updated based on more accurate calculations and the annual tons per year (tpy) limit was set to limit facility emissions below 249 tpy.

With the recent removal of the six Clark compressor engines (manf. 1950s), the PTE for CO was recalculated without synthetic limits and found to be below 250 tpy; the Department removed all CO limits (both emissions and hours).

[1] See SLEIS 2021-2025 reported emissions.
[2] Further justification for low sulfur contents can be found from north low-pressure inlet testing conducted in 2020 available on CERIS-ND.

Similarly, the PTE for NO_X was recalculated but found to be above 250 tpy without synthetic limitations; therefore, the Department proposed to remove all NO_X limits and replace them with a nested cap of 123 tpy on the 5 largest NO_X contributors (EUs C-30100, C-30200, C-30300, H-5704, & H-5714). Compliance will be demonstrated by emission testing of each EU, and based on recent SLEIS reported emission data, compliance is expected. This testing will occur after PTC issuance and once per permit term, integrated into the Title V operating permit.

Reclassification from a PSD major to synthetic minor source comes with certain limitations. To avoid potential sham permitting and circumvention of the PSD rules and although the facility is not a PSD major source, the Department will artificially consider the facility a PSD major source for the purposes of major modification; future Projects would be subject to PSD review if PTE exceeded SER thresholds, not the major source thresholds.[3] This requirement will be integrated into the facility's Title V operating permit at the next revision and will be removed at the next renewal 5 years after its integration.

For a full summary of monitoring and recordkeeping requirements to be integrated into the Title V permit at the next revision/renewal, see Appendix A: Future Title V Monitoring and Recordkeeping Requirements attached to this document.

In summary, the facility will remain a Title-V major source and an area HAP source, but it will be reclassified as a synthetic minor source for PSD (see Table 1).

[3] The significant emission rates (SERs) are defined under 40 CFR 51.165(a)(1)(x)(A).

2. Potential to Emit

The facility remains a Title V major source, but PSD minor and area HAP source. PTE provided by Hess on April 15, 2026 is displayed in Table 1 and is considered representative of PTE.

Table 1 – Facility PTE and Major Source Applicability. All units are in tpy.

	NO_X	**CO**	**SO_2**	**VOC**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**Total HAP**	**n-Hexane (Largest HAP)**
Facility PTE (only fugitives)	-	-	-	99.1	-	-	-	5.6	1.4
Facility PTE (without fugitives) [A]	215.7	207.1	248.7	191.4	14.4	14.4	14.4	11.2	4.7
PSD Major Source Thresholds	250	250	250	250	250	250	250	N/A	N/A
PSD Major Source?	**No**	**No**	**No**	**No**	**No**	**No**	**No**	N/A	N/A
Title V Threshold	100	100	100	100	100	100	100	25	10
Title V Major Source?	**Yes**	**Yes**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**

[A] Fugitive emissions were not considered because the facility does not fall under a PSD or Title V source category.

3. Updated Regulatory Applicability

All previously unrepresented EUs and their regulatory applicability are summarized in this section.

The natural gas-fired oil heater treater (EU F-7A) was added, has a maximum design heat input less than 10 MMBtu/hr (actual of 0.5 MMBtu/hr), and is therefore exempt from NSPS Dc.

The emergency engines (EUs G-1, G-2, G-5, & FWP-1) are additionally subject to MACT ZZZZ, but this adds no requirements due to their emergency status and is therefore not listed on the PTC.

The facility has three crude oil tanks (EUs D-64A, D-64B, & D-64C) constructed after July 23, 1984 and before October 4, 2023 with a capacity greater than 471 barrels[4] (actual of 500 barrels each), making them subject to NSPS Kb. They are controlled using a closed vent system and a vapor recovery unit.

There are three slop oil tanks (EUs D-29, D-30, & D-31) constructed after October 4, 2023 with a capacity greater than 476 barrels[5] (actual of 500 barrels each), making them subject to NSPS Kc. They are also controlled using a closed vent system and a vapor recovery unit.

Additional small tanks were included which do not have regulatory applicability due to capacities less than 472[6] barrels or VOC emissions below 6 tpy: two methanol tanks (EUs D-99 & TK-9796), a gasoline tank (EU D-51), a diesel tank (EU D-90), and a TEG tank (EU TK-9285).

Nine reciprocating compressors (EUs C-5461, C-5471, C-5481, C-5630, C-5631, C-5401, C-5421, SOC-5012, & SOC-5055) are affected facilities under NSPS OOOO. An additional inlet reciprocating compressor (EU C-36100) is an affected facility under NSPS OOOOa.

Fugitive emissions were included, and the facility is subject to the applicable standards for equipment leaks at onshore natural gas processing plants under NSPS OOOOa (40 CFR 60.5400a).

4. Conclusion

After a complete review of the proposed project indicating that the facility is expected to comply with applicable federal and state air pollution rules and regulations, the Department will make a recommendation on PTC issuance for Hess Tioga Gas Plant following the completion of a thirty-day public comment period. The public comment period will run from April 16, 2026, through May 16, 2026.

[ERY]:

[4] 75m^3 as specified under 40 CFR 60.110b(a) converted to barrels
[5] 75.7m^3 as specified under 40 CFR 60.110c(a) converted to barrels
[6] 75m^3 as specified under 40 CFR 60.110b(a) and 40 CFR 60.110c(a) converted to barrels

Appendix A: Future Title V Monitoring and Recordkeeping Requirements

4. Monitoring Requirements

The permittee must comply with the monitoring requirements in Table 1 and the conditions of this section.

Table 1 – Monitoring Requirements

EU Description	EP	Pollutant/ Parameter	Method	Condition Number	Regulatory Justification
Natural gas-fired turbines and duct burners & natural gas-fired heaters	C-30100 C-30200 C-30300 F-2 F-3	NO_X	Emission Test & Calculations	4.A	NDAC 33.1-15-14-06.5.a(3)(a) & ACP-18224 v1.0
		SO_2	Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity	Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
Natural gas-fired heaters	F-1 F-5A F-5B F-5C F-7A	SO_2 Opacity	Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
Natural gas-fired boilers	B-1 B-2 B-3 B-4 B-5	SO_2 Opacity	Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
Natural gas-fired emergency generators (2011, 2012, & 2020, NSPS JJJJ)	G-1 G-2 G-5	Operating Hours	Recordkeeping	4.C	NSPS JJJJ
		SO_2		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
Cummins KTA28 diesel-fired emergency generator (1999, MACT ZZZZ)	G-4	Operating Hours	Recordkeeping	4.C	MACT ZZZZ
		SO_2		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity		4.B	NDAC 33.1-15-14-06.5.a(3)(a)

EU Description	EP	Pollutant/ Parameter	Method	Condition Number	Regulatory Justification
Diesel-fired firewater pump engine (2011, certified NSPS IIII)	FWP-1	Operating Hours	Recordkeeping	4.C	NSPS IIII
		SO_2		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
Diesel-fired firewater pump engine (1994 & 1990, MACT ZZZZ)	FWP-2 FWP-3	Operating Hours	Recordkeeping	4.C	MACT ZZZZ
		SO_2		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity		4.B	NDAC 33.1-15-14-06.5.a(3)(a)
Tri-tip flare (north) (acid gas flare burns auxiliary natural gas)	S-5811 (cryogenic)	Opacity	Recordkeeping	4.D	NDAC 33.1-15-14-06.5.a(3)(a)
	S-5821 (acid gas)	SO_2	Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity		4.D	
	S-5841 (process)	Opacity	Recordkeeping	4.D	NDAC 33.1-15-14-06.5.a(3)(a)
High-pressure flare (south)	S-102	Opacity	Recordkeeping	4.D	NDAC 33.1-15-14-06.5.a(3)(a)
Spyder high-pressure flare	S-5870	Opacity	Recordkeeping	4.D	NDAC 33.1-15-14-06.5.a(3)(a)
Amine SRU and Claus reactor furnace sending tail gas to a thermal oxidizer	S-302	SO_2	CERMS	4.E	ACP-18224 v1.0
			SO_2 Emission Calculations	4.E	ACP-18224 v1.0
			Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity	VEE	4.E	ACP-18224 v1.0
Natural-gas fired TEG reboiler	E-9271	SO_2	Recordkeeping	4.B	NDAC 33.1-15-14-06.5.a(3)(a)
		Opacity			
Fugitive emissions (NSPS OOOOa)	FUG	VOC	LDAR	4.F	NSPS OOOOa

A. <u>NO_X Emission Testing, Calculations, and Reporting</u>:

1) NO_X Emission Testing

Once per permit term, the permittee must conduct an NO_X emission test for each subject emission point (EPs C-30100, C-30200, C-30300, F-2, & F-3) using an EPA approved test method under 40 CFR 60 Appendix A, or at a minimum, a portable analyzer method approved by the Department. A test must consist of at least three runs and at least 20 minutes per run. Testing undertaken to satisfy the initial testing requirements of ACP-18224 v1.0 may be used to demonstrate compliance with condition 4.A.1 if that test data is not more than 5 years old.

2) NO_X Calculations and Reporting

On the 15th of each month, the permittee must calculate and record the sum of NO_X emissions from the turbines (EUs C-30100, C-30200 & C-30300) and heaters (EUs F-2 & F-3) for the previous 12 months. Emissions must be calculated using equation 1,

$$Total\ NO_X\ (tpy) = \sum hours\ of\ operation\left(\frac{hr}{yr}\right) \cdot tested\ emission\ rate\ \left(\frac{lb}{hr}\right) \cdot \left(\frac{ton}{2000\ lb}\right) (1)$$

where the contribution of each of the 5 emission units listed above is summed, hours of operation are totaled for the previous 12 months, and the emission rate from the most recent tests are used. In the event that combined emissions exceed 123 tpy of NO_X, the permitee must notify the Department by the 25th day of the month in which the exceedance was calculated.

If each unit is assumed to operate for 8,760 hours per year and total emissions do not exceed 123 tpy of NO_X as calculated using equation 1, then compliance with condition 4.A.2 is sufficiently demonstrated; no monthly compliance demonstration is required until more recent testing data becomes available, at which time the permittee must furnish to the Department recalculated total emissions to demonstrate compliance per the above.

B. Compliance Demonstrated Through Recordkeeping

For purposes of compliance monitoring, records verifying the burning of fuels outlined in Condition 2.A are considered creditable evidence of compliance. However, results from tests conducted in accordance with the test methods in 40 CFR 50, 51, 60, 61, or 75 will take precedence over the burning of fuel as outlined in Condition 2.A for evidence of compliance or noncompliance with the limit in the event of enforcement action.

C. Emergency Unit Operating Hours:

A log must be kept of the hours of operation, maintenance conducted, and certifications (if applicable):

1) For each emergency engine, a log must be kept of the total hours of operation on a calendar year basis for each of the engines. Records must be maintained to differentiate annual emergency, non-emergency, maintenance, and other hours of operation. To maintain emergency engine status, these totals must be less than the applicable totals under the rotating internal combustion engine (RICE) rules (NSPS IIII, NSPS JJJJ, & MACT ZZZZ).

2) For a certified engine, the permittee must collect operational and maintenance data to demonstrate compliance with the engine manufacturer's emission-related written instructions [40 CFR 60.4211(a)].

D. Flare Requirements (EUs S-101, S-102, & S-5870):

During each flaring occurrence, a trained company representative (need not be certified) must observe the emission point. If no visible emissions are observed, the date and time must be recorded. If visible emissions are observed:

1) The permittee must conduct a formal visible emissions evaluation of the flare to determine if the emissions comply with the applicable opacity standard. Opacity readings must consist of three consecutive six-minute periods using EPA Reference Method 9 and be conducted by a certified visible emissions reader.

2) The permittee must investigate for a potential problem within eight hours and correct any discovered problems as soon as possible. If the formal visible emission reading resulted in noncompliance, and the correction is expected to take longer than 24 hours, the permittee must follow the procedures outlined in Condition 7.G.[7] Following corrective maintenance, a visible emissions observation must be made by a trained company representative (need not be certified) and the steps above be repeated until the issue is resolved.

All investigations of malfunctions and visible emissions must be recorded. The permittee must comply with the opacity limit and nothing in this condition must be construed as authorizing otherwise.

E. Amine Unit Incinerator Stack (EP S-302)

This Condition is invalidated at such a time that the SRU (EUs S-302, H-301, & H-306) is decommissioned and incapable of emitting SO_2.

1) The permittee must calibrate, maintain, and operate equipment for continuously monitoring and recording sulfur dioxide emissions on a lb/hr basis from the sulfur plant incinerator stack (EP S-302). The monitoring and recording must be in accordance with the requirements for notification and recordkeeping under 40 CFR 60.7 and monitoring requirements under 40 CFR 60.13 or quality assurance procedures approved in advance by the Department. The data recording system must record the emission rate on both a 24-hour rolling average basis and a l-hour block average basis.

2) The permittee must conduct a performance evaluation of the SO_2 continuous

[7] Of the current Title V permit to operate, "Shutdowns/Malfunctions/Continuous Emission Monitoring System Failure"

emission rate monitoring system (CERMS) between two and three years from the date of the previous performance evaluation. The performance evaluation must be conducted in accordance with the relative accuracy (RA) provisions of Performance Specification 6 of 40 CFR 60, Appendix B. The performance evaluation report must be submitted within 60 days after completion of the performance evaluation. The Department may require additional performance audits of the CERMS system.

3) When a failure of the CERMS occurs, a Department-accepted alternative SO_2 monitoring method must be undertaken as soon as possible. Timely repair of the emission monitoring system must be made.

4) By the 15th day of each month, the permittee must record the total SO_2 emissions from the Amine Unit (EP S-302) for the previous 12-month period. In the event that SO_2 emissions exceed 219 tons in a 12-month period, the permittee must notify the Department by the 25th day of the month in which the calculation was made.

5) Once per month, the permittee must conduct a formal visible emissions evaluation (VEE) of the sulfur plant incinerator stack (EP S-302) to determine if emissions comply with the applicable opacity standard. Opacity readings must consist of three consecutive six-minute periods using EPA Reference Method 9 and be conducted by a certified visible emissions reader. During periods of plant upsets which result in increased opacity from the incinerator, opacity must be observed hourly following the first hour of the plant upset in the same manner as above.

F. Fugitive Emissions

For all affected fugitive components subject to NSPS OOOOa, the permittee must comply with the inspection, monitoring, and leak repair requirements of NSPS OOOOa.

5. Recordkeeping Requirements

The permittee must maintain compliance monitoring records as outlined in Table 2 that include the following information:

- The date, place (as defined in the permit), and time of each sampling or measurement
- The date(s) testing was performed
- The company, entity, or person that performed the testing
- The testing techniques or methods used
- The results of such testing
- The operating conditions that existed during testing of the turbines (i.e., ambient conditions, horsepower & rpm, air to fuel ratio, temperatures, tested load compared to rated capacity, suction/discharge pressures, etc.)

- The operating conditions that existed during testing of the Amine Unit (EU S-302)(i.e., tail gas flowrate, stack temperature, sulfur recovered, and inlet gas H_2S content)
- The records of quality assurance for emission measuring systems, including but not limited to, quality control activities, audits, and calibration drifts as required by the applicable test method, standard or monitoring equipment.
- A copy of all field data sheets from all emission testing

Applicable Requirement: NDAC 33.1-15-14-06.5.a(3)(b)[1]

Table 2 – Recordkeeping Requirements

EU Description	EP	Pollutant/ Parameter	Compliance Monitoring Record
Natural gas-fired turbines and duct burners & natural gas-fired heaters	C-30100 C-30200 C-30300 F-2 F-3	NO_X SO_2 Opacity	Emission Test Data & NO_X Calculation Data Type of Fuel Usage Data Type of Fuel Usage Data
Natural gas-fired heaters	F-1 F-5A F-5B F-5C F-7A	SO_2 Opacity	Type of Fuel Usage Data
Natural gas-fired boilers	B-1 B-2 B-3 B-4 B-5	SO_2 Opacity	Type of Fuel Usage Data
Natural gas-fired emergency generators (2011, 2012, & 2020, NSPS JJJJ)	G-1 G-2 G-5	Operating Hours SO_2 Opacity	Hours of Operation Data Type of Fuel Usage Data Type of Fuel Usage Data
Cummins KTA28 diesel-fired emergency generator (1999, MACT ZZZZ)	G-4	Operating Hours SO_2 Opacity	Hours of Operation Data Type of Fuel Usage Data Type of Fuel Usage Data

EU Description	EP	Pollutant/ Parameter	Compliance Monitoring Record
Diesel-fired firewater pump engine (2011, certified NSPS IIII)	FWP-1	Operating Hours SO_2 Opacity	Hours of Operation Data Type of Fuel Usage Data Type of Fuel Usage Data
Diesel-fired firewater pump engine (1994 & 1990, MACT ZZZZ)	FWP-2 FWP-3	Operating Hours SO_2 Opacity	Hours of Operation Data Type of Fuel Usage Data Type of Fuel Usage Data
Tri-tip flare (north) (acid gas flare burns auxiliary natural gas)	S-5811 (cryogenic)	Opacity	VEE Data
	S-5821 (acid gas)	SO_2 Opacity	Type of Fuel Usage Data VEE Data
	S-5841 (process)	Opacity	VEE Data
High-pressure flare (south)	S-102	Opacity	VEE Data
Spyder high-pressure flare	S-5870	Opacity	VEE Data
Amine SRU and Claus reactor furnace sending tail gas to a thermal oxidizer	S-302	SO_2 Opacity	CERMS Data & SO_2 Calculation Data & Type of Fuel Usage Data VEE Data
Natural-gas fired TEG reboiler	E-9271	SO_2 Opacity	Type of Fuel Usage Data
Fugitive emissions (NSPS OOOOa)	FUG	VOC	LDAR Inspection, Monitoring, and Repair Data

In addition to requirements outlined above, recordkeeping must be conducted in accordance with the following requirements of 40 CFR 60 & 63 as applicable:

1) NSPS A, 40 CFR 60.7, Notification and Recordkeeping
2) NSPS Dc 40 CFR 60.48c, Reporting and Recordkeeping Requirements
3) NSPS Kb, 40 CFR 60.115b, Reporting and Recordkeeping Requirements

4) NSPS Kc, 40 CFR 60.115c, Reporting and Recordkeeping Requirements

5) NSPS IIII, 40 CFR 60.4214, Notification, Reporting, and Recordkeeping Requirements

6) NSPS JJJJ, 40 CFR 60.4245, Notification, Reporting, and Recordkeeping Requirements

7) NSPS OOOO, 40 CFR 60.5240 and 60.5421, Notification, Reporting, and Recordkeeping Requirements and Additional Recordkeeping Requirements

8) NSPS OOOOa, 40 CFR 60.5240a and 60.5421a, Notification, Reporting, and Recordkeeping Requirements and Additional Recordkeeping Requirements

9) MACT A, 40 CFR 62.10, Recordkeeping and Reporting Requirements

10) MACT ZZZZ, 40 CFR 63.6655 through 60.6660, Notifications, Reports, and Records

The permittee must retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sampling, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings/computer printouts of continuous monitoring instrumentation, and copies of all reports required by the permit.

Applicable Requirement: NDAC 33. 1-l 5-14-06.5.a(3)(b)[2]