WENCK File #B5620-0068
May 2020

Permit to Construct/Tier I Operating Permit Significant Modification Application

Gas Transmission Northwest LLC
Compressor Station 5
Athol, Idaho



Prepared for:

Gas Transmission Northwest, LLC

700 Louisiana Street
Houston, TX 77002

TC Energy

WENCK
Responsive partner.
Exceptional outcomes.

Prepared by:

WENCK Associates, Inc.
1800 Pioneer Creek Center
Maple Plain, MN 55359
Phone: 763-479-4200
Fax: 763-479-4242

Table of Contents

1.0 INTRODUCTION 1-1

2.0 PROJECT DESCRIPTION AND EMISSION CALCULATIONS 2-1

2.1 Project Schedule 2-2
2.2 Site Description and Diagram 2-2
2.3 Permitting Summary and Compliance History 2-2

3.0 REGULATORY ANALYSIS AND COMPLIANCE METHODS 3-1

3.1 Prevention of Significant Deterioration 3-1
3.2 New Source Performance Standards 3-2
3.2.1 Stationary Spark Ignition Internal Combustion Engines (40 CFR 60 Subpart JJJJ) 3-2
3.2.2 Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015 (40 CFR 60 Subpart OOOOa) 3-3
3.2.3 Stationary Gas Turbines (40 CFR 60 Subpart KKKK) 3-3
3.3 National Emission Standards for Hazardous Air Pollutants 3-4
3.4 Compliance Assurance Monitoring (40 CFR 64) 3-4
3.5 Pre-Construction Permitting 3-5
3.6 Requirements for Operating Permitting 3-5
3.7 Air Dispersion Modeling Requirements 3-5

TABLES

Table 3-1: Emissions Comparison for PSD Applicability (tpy) 3-2
Table 3-2: Proposed Turbine and Corresponding Category and Emission Standard 3-3

APPENDICES

A Area Maps and Process Flow Diagrams
B Emission Calculations
C Unit 5B and Emergency Generator Baseline Actual Emissions
D PTC/Tier I Significant Modification Application Forms
E Air Dispersion Modeling Report

1.0 Introduction

TC Energy owns and operates the Gas Transmission Northwest LLC (GTN) – Compressor Station 5 located in Athol, ID. The coordinates of the station are approximately Latitude: 49.9177, and Longitude: -116.755. The station is in Kootenai County at 2244 E. Seasons Road in Athol, ID.

GTN is proposing to modify Compressor Station 5. Construction of the proposed project is scheduled to begin to March 2021. This application package contains GTN's application to:

- Replace one (1) existing Cooper Coberra Turbine (Unit 5B) with a new 21,087 hp Solar Titan 130 turbine (Unit 5D);
- Replace one (1) existing emergency generator with a new emergency generator (1,827 HP) (Unit AUX-1); and
- Fugitive equipment leaks and blowdowns for the proposed turbine.

Compressor Station 5 also consists of an existing Cooper Coberra turbine (Unit 5C), an existing heater, existing pipeline fluids tanks and fugitive equipment leaks and blowdowns. All existing equipment listed above will remain at Compressor Station 5.

This Permit to Construct (PTC)/Tier I Significant Permit Modification Application is comprised of the following information:

- Section 1 consists of introduction;
- Section 2 consists of project description and emission calculations;
- Section 3 consists of regulatory analysis and compliance methods
- Appendix A contains the area maps and process flow diagrams for the project;
- Appendix B contains the project emission calculations;
- Appendix C contains the Unit 5B and emergency generator baseline actual emissions;
- Appendix D consists of the PTC/Tier I Significant Modification application forms; and
- Appendix E contains a modeling report for the proposed project.

2.0 Project Description and Emission Calculations

Compressor Station 5 transports natural gas along the pipeline by receiving low-pressure inlet natural gas and compressing the stream to increase the pressure and maintain the downstream flow. Compressor Station 5 is covered by Standard Industrial Classification (SIC) 4922 and has the potential to operate seven (7) days per week, twenty-four (24) hours per day.

The one (1) proposed 21,087 hp Solar Titan 130 turbine is designated as Unit 5D. Appendix A includes a process flow diagram showing the proposed equipment only.

The new Solar Turbine will be equipped with advanced dry-low-NOx combustion controls, known by the manufacturer as SoLoNO$_x$. These controls reduce nitrogen oxides (NO$_x$) and peak combustion temperatures through the use of a lean, premixed air/fuel mixture and advanced combustion controls. The SoLoNO$_x$ system is operational at turbine loads from approximately 50% to 100% of full load. During operation at low turbine loads (<50% of full load) and during turbine startup and shutdown, supplemental pilot fuel is fired for flame stability and results in NO$_x$, carbon monoxide (CO), and volatile organic compounds (VOC) concentrations that are higher than during SoLoNO$_x$ operation. Estimated emissions during each of the operating modes are summarized in Appendix B with the turbine calculations.

The new Solar turbine is expected to continuously operate; therefore, emission estimates are based on 8,760 operating hours per year. Because the SoLoNO$_x$ controls cannot operate properly below 50% of peak load, the potential emission estimates presented in Table B-3 includes separate lines for operating hours at low load (less than 50% load) and startup/shutdown cycles. Annual emissions from the proposed turbine during the rest of the year are conservatively based on an ambient temperature of 32°F. Combustion turbine power varies with atmospheric conditions such that maximum heat input, maximum fuel consumption, and associated emissions generally increase as ambient temperature decreases. For the purpose of this application, turbine emissions have been characterized based on an ambient temperature of 32°F. The average maximum daily temperature for Kootenai County, ID is 59.1°F, and the average minimum daily temperature is 36.8°F.

Except as indicated above, potential emissions for each combustion unit are based on the following emission factors.

- Potential CO_2e emissions are based on emission factors and global warming potential specified in 40 CFR Part 98.
- Annual SO_2 emissions are based on 0.25 grains of sulfur per 100 standard cubic feet of natural gas, and maximum hourly emissions are based on 20 grains of sulfur per 100 standard cubic feet.
- Emissions of formaldehyde and total HAPs are based on the EPA's AP-42 emission factors (except for the emergency generator).

GTN will also be replacing the existing 691 HP emergency generator with a larger 1,827 HP emergency generator. Potential emissions for the proposed generator are based on operation of up to 500 hours per year and are based on NSPS Subpart JJJJ emission limitations for NO$_x$, CO, and VOC, and AP-42 emission factors for other air pollutants. Formaldehyde emissions for the proposed emergency generator were calculated based on vendor data.

Potential annual emissions of NO_x, CO, VOC, greenhouse gases as carbon dioxide equivalents (CO_2e), sulfur dioxide (SO_2), respirable particulate matter with an aerodynamic diameter of less than or equal to 10 microns (PM_{10}), fine particulate matter with an aerodynamic diameter of less than or equal to 2.5 microns ($PM_{2.5}$), formaldehyde [(CH_2O), the primary hazardous air pollutant (HAP)], and total HAPs from all sources associated with the project are provided in Table B-1 of Appendix B. Source-specific emissions calculations are also provided in Appendix B.

Athol, ID is classified as attainment or unclassifiable for all National Ambient Air Quality Standards for all pollutants for which National Ambient Air Quality Standards (NAAQS) have been promulgated.

2.1 PROJECT SCHEDULE

GTN proposes to begin construction of the new turbine compressor at Compressor Station 5 in March 2021 in order to meet an anticipated startup date of October 2021. The unit will be operated at a lower horsepower (HP) until November 2023 when it will be operated at the full capacity of 21,087 HP.

GTN is proposing to demolish and replace the existing combustion turbine, Unit 5B (Cooper Rolls - 14,300 hp ISO) along with associated piping and ancillary equipment starting in August 2020. No construction activity will occur until an PTC/Tier I Significant Modification is issued.

2.2 SITE DESCRIPTION AND DIAGRAM

Compressor Station 5 is located in Athol, Kootenai County, Idaho. The facility layout consists of two (2) compressor buildings, a warehouse and control building, auxiliary generator building and other minor structures and exposed operating equipment (e.g. valves, piping, coolers, etc.).

2.3 PERMITTING SUMMARY AND COMPLIANCE HISTORY

Compressor Station 5 currently operates under a Tier I Operating Permit (Permit No. T01-2016.0024). The permit was most recently issued on May 2, 2017 and will expire on May 2, 2022.

Prior to the proposed project. the station was a major source with respect to New Source Review (NSR); therefore, the major source NSR Program will also apply to this project. GTN reviewed the project to determine if it would trigger Prevention of Significant Deterioration (PSD) review. Based on future potential emissions for the proposed equipment and baseline actual emissions for Unit 5B and the existing emergency generator, the project does not trigger PSD review. Additional discussion is provided below.

Compressor Station 5 will continue to be a major source with respect to PSD following the project. In addition, Compressor Station 5 is currently a minor source with respect to HAPs and will continue to be after the proposed project.

3.0 Regulatory Analysis and Compliance Methods

This section reviews the applicability of state and federal regulations potentially affecting the new emission units and proposed compliance procedures.

3.1 PREVENTION OF SIGNIFICANT DETERIORATION

Idaho implements the PSD permitting program pursuant to the USEPA-approved Idaho Administrative Procedure Act (IDAPA) 58.01.01.205 which closely mirrors federal PSD regulations at 40 CFR §52.21. As indicated previously, Compressor Station 5 is a major source under PSD rules. For a major stationary source such as the existing Station, PSD requirements apply to projects that have the potential to increase annual emissions beyond defined significance levels. This potential is evaluated as a two-step process. First, any emissions increase associated with the project itself is evaluated. If the project will result in a significant emissions increase, then the net emissions increase, considering all contemporaneous equipment changes must be evaluated based on the definition of net emissions increase at 40 CFR Part 52.21(B)(3)(i).

Future emissions calculations for the PSD applicability analysis are provided in Appendix B, and potential annual emissions associated with the Project are summarized in Table B-2. For PSD-regulated pollutants other than NOx and CO, the potential Project emissions are below the significant emissions increase thresholds; therefore, PSD is not applicable to emissions increases at Step 1 of the PSD applicability procedure. For NOx and CO emissions, the potential annual emissions from the new equipment exceed the PSD significance level; therefore, the net emissions change was determined following PSD Step 2 applicability procedures.

All contemporaneous changes must be considered when determining the net emission increase. Baseline NOx and CO emissions from Unit 5B and the existing emergency generator that will be retired are presented in Appendix C. The contemporaneous period is defined as 5 years prior to the date construction commences for the proposed project. As described above, the project is proposed to begin construction in March 2021. Therefore, the contemporaneous period will begin in March 2016.

The net change in NOx and CO emissions associated with the proposed Project is presented in Table 3-1 as the potential new emissions from the Project minus baseline (actual) emissions from Unit 5B. This table provides a comparison of these net emission changes to the PSD significance level. As presented in Table 3-1 below, the net change in annual emissions is less than the PSD significance level for NOx and CO. Therefore, the proposed Project is NOT subject to PSD requirements.

To ensure that future emissions remain below the PSD significance levels, GTN will accept requirements to monitor turbine operating mode (e.g., low temperature, low load, startup/shutdown) and to monitor fuel usage to ensure that actual emissions, accounting for these non-SoLoNOx conditions, do not exceed the proposed potential annual emission rates.

Table 3-1: Emissions Comparison for PSD Applicability (tpy)

	NOx	CO
Total Potential Emissions from the Project	43.85	133.45
Baseline Emissions	62.76	111.87
Net Change[1, 2]	-18.91[3]	21.59
PSD Significance Level	40	100

[1] See Appendix B for details.
[2] Total potential emissions from the Project minus baseline (past actual) emissions.
[3] Note: the increase in actual emissions is creditable only to the extent that the new level of emissions exceeds the old level.

On June 23, 2014, the U.S. Supreme Court issued a decision that greenhouse gas emissions could not be a basis for PSD or Title V applicability, and this decision was followed by a July 24, 2014 memorandum from the USEPA that stated that the USEPA will comply with the Court's decision and will not apply or enforce regulations that would require a PSD permit where PSD would be applicable solely because of GHG emissions. Therefore, CO_2e emissions are no longer considered for PSD applicability.

3.2 NEW SOURCE PERFORMANCE STANDARDS

New Source Performance Standards (NSPS) apply to new, modified or reconstructed stationary sources meeting criteria established in 40 CFR Part 60. The following sections describe requirements that apply to the proposed units at Compressor Station 5.

3.2.1 Stationary Spark Ignition Internal Combustion Engines (40 CFR 60 Subpart JJJJ)

Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines) applies to stationary spark ignition engine manufacturers and owners/operators. For natural gas-fired emergency engines manufactured after January 1, 2009, the applicable emission limits for engines greater than 130 hp rated capacity are specified in Table 1[1]of Subpart JJJJ as follows.

- For NO_x, the limit is 2.0 g/hp-hr or 160 ppmvd at 15 percent 0_2;
- For CO, the limit is 4.0 g/hp-hr or 540 ppmvd at 15 percent 0_2; and
- For VOC, the limit is 1.0 g/hp-hr or 86 ppmvd at 15 percent 0_2.

The proposed emergency generator will be subject to the Subpart JJJJ emission limits for engines greater than 130 hp. In accordance with 40 CFR §60.4243(a)(2)(iii) if this engine is not certified an initial performance test is required within one year of startup. Subsequent performance testing is required every 8,760 hours of operation or every three years whichever comes first. Note that Caterpillar does not currently certify this engine. Based on manufacturer data, the engine will comply with these emission limits listed above.

[1] Compliance with the emission limits specified in Table 1 of Subpart JJJJ is required by 40 CFR §60.4233(e).

3.2.2 Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015 (40 CFR 60 Subpart OOOOa)

The EPA has promulgated a NSPS for crude oil and natural gas facilities in 40 CFR 60 Subpart OOOOa. Compressor Station 5 was not previously subject to Subpart OOOOa as the equipment and processes potentially subject to the regulation were installed prior to the applicability date of Subpart OOOOa. However, fugitive emissions from the components of the proposed Solar Turbine will be subject to the requirements of Subpart OOOOa per 40 CFR §60.5365a(j).

3.2.3 Stationary Gas Turbines (40 CFR 60 Subpart KKKK)

The USEPA has promulgated NSPS for stationary combustion turbines in 40 CFR 60 Subpart KKKK. The proposed Solar turbine, that has a peak heat input of 10 MMBtu/hr or greater, will be subject to the requirements of Subpart KKKK per 40 CFR §60.4305(a). Sources covered by Subpart KKKK are exempt from the requirements in Subpart GG (the previous combustion turbine NSPS) per 40 CFR §60.4305(b). The subcategory and corresponding NOx emission standard as established in Table 1 of Subpart KKKK for each of the proposed turbines is presented in Table 3-2 below.

Table 3-2: Proposed Turbine and Corresponding Category and Emission Standard

Unit	Table 1 Subcategory	Heat Input	NO_x Emission Standard	Manufacturer's Warranty
Solar Turbine Titan 130 (Unit 5D)	New turbine firing natural gas	> 50 MMBtu/hr and ≤ 850 MMBtu/hr	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh)	15 ppm at 15% O_2

Table 3-2 of Subpart KKKK also establishes a NO_x emission limit of 150 ppm at 15% O_2 or 1,100 ng/J of useful output (8.7 lb/MWh) for turbines with a peak capacity equal to or less than 30 MW output which are operating at less than 75% of peak load or at temperatures less than 0°F.

The fuel sulfur limit in Subpart KKKK is 0.060 lb SO_2/MMBtu. Under 40 CFR §60.4365, a source is exempt from monitoring fuel sulfur content if the source burns natural gas that is covered by a purchase or transportation agreement with maximum sulfur content of 20 grains per 100 scf, which is the case for the proposed turbine fuel.

The proposed NO_x emission rates and fuel sulfur levels comply with NSPS limits. To demonstrate compliance with Subpart KKKK, 40 CFR §60.4400 requires an initial NO_x performance test using EPA reference methods. The initial compliance test must be conducted within 60 days after achieving full-load operation or within 180 days of startup if the turbines are not operated at full load. Annual performance testing using EPA reference methods must be conducted within 14 calendar months following the previous performance test. The test frequency can be reduced to biennial if measured NO_x emissions are less than 75% of limit. In addition, GTN will continuously monitor Unit 5D to document any operating periods during which the SoLoNO$_x$ system is not in service (e.g., during startup, shutdown, low-load, or a system malfunction). Records of turbine startup, shutdown, SoLoNO$_x$ malfunction, and/or SoLoNO$_x$ monitoring system malfunction will be recorded per Subpart KKKK and NSPS General Provisions in 40 CFR §60.7(b)&(c). Please note, GTN will complete

an initial performance test for Unit 5D once operating at the lower load and again when Unit 5D is operating at full load.

GTN will use the FERC tariff to show compliance with the SO_2 and fuel sulfur limits per 40 CFR §60.4365(a).

3.3 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

National Emission Standards for Hazardous Air Pollutants (NESHAP) are promulgated under 40 CFR Part 63 for specific processes and HAP emissions. Compressor Station 5 following the proposed project will have potential HAP emissions that are less than the major source threshold and will therefore be considered an area source of HAPs.[2]

40 CFR 63 Subpart YYYY for stationary combustion turbines is only applicable to major sources of HAPs per 40 CFR §63.6085; therefore, the proposed Solar turbine is not subject to this regulation.

Subpart ZZZZ for stationary reciprocating internal combustion engines is applicable to the proposed emergency generator. The proposed emergency generator is a new stationary reciprocating internal combustion engine located at an area source of HAPs. As such, the engine meets the requirements of Subpart ZZZZ by meeting the requirements of NSPS Subpart JJJJ per 40 CFR §63.6590(c)(1). No further requirements apply.

There are two NESHAPs which regulate emissions from industrial, commercial and institutional boilers - 40 CFR 63 Subpart DDDDD (major sources of HAPs) and 40 CFR 63 Subpart JJJJJJ (area sources of HAPs). As indicated above, Compressor Station 5 following the project will remain an area source of HAPs; Subpart JJJJJJ is the applicable NESHAP for the Station. Per 40 CFR §63.11195(e), natural gas-fired sources are exempt from the requirements of this Subpart.

3.4 COMPLIANCE ASSURANCE MONITORING (40 CFR 64)

Compliance Assurance Monitoring (CAM) requirements in 40 CFR Part 64 are intended to assure that emission control equipment is properly operated and maintained. CAM applies to emission units that:

1. have an emission limitation,
2. use a control device to comply with the emissions limit, and
3. have sufficient emissions to be classified as a major emission source under 40 CFR Part 70.

As defined in 40 CFR §64.1, "control device" means add-on control equipment other than inherent process equipment that is used to destroy or remove air pollutant(s) prior to discharge to the atmosphere. The definition also states that "a control device does not include use of combustion or other process design features or characteristics."

Exemptions specified in 40 CFR §64.2(b) include units complying with an emission limitation or standard proposed by the USEPA after November 15, 1990 pursuant to Section 111 or 112 of the Clean Air Act (NSPS or NESHAP).

[2] Per 40 CFR §63.2, an area source of HAPs is defined as a stationary source or group of sources with the potential to emit less than 10 tpy of any HAP and less than 25 tpy of any combination of HAPs.

The proposed turbine will not use any add-on emission controls and will be subject to a federal NSPS promulgated after 1990. As such, the proposed turbine is exempt from CAM requirements.

3.5 PRE-CONSTRUCTION PERMITTING

Idaho's air pollution control rules require the owner or operator of any stationary source that emits or may emit air pollution to obtain a PTC from Idaho Department of Environmental Quality (IDEQ) before beginning construction or modifying the source (unless the activity is specifically exempt from the need to obtain a permit). The enclosed permit application forms are for a PTC to authorize construction of the proposed project.

3.6 REQUIREMENTS FOR OPERATING PERMITTING

After this Project, Compressor Station 5 will continue to be classified as a major source under Title V regulations. A Tier I Significant Modification application to revise the Station's Tier I operating permit is being submitted along with the PTC to IDEQ as part of the application package. An updated Tier I permit must be issued prior to operation of the proposed equipment.

3.7 AIR DISPERSION MODELING REQUIREMENTS

According to the State of Idaho Guideline for Performing Air Quality Impacts Analysis (Doc. ID AQ-001, September 2013), a modeling analysis is generally required with each permit application for new construction or a modification that results in an increase in emissions of pollutants for sources permitted by DEQ.

Idaho Air Rules Section 203 and 403 state that a permit to construct (PTC) or Tier II operating permit will not be granted unless the applicant demonstrates the following:

1) the new source, modification, or facility would not cause or significantly contribute to the violation of any air quality standard;
2) the emissions increase in Toxic Air Pollutants (TAPs) would not injure or unreasonably affect human or animal life or vegetation as required by Idaho Air Rules Section 161, using methods provided in Idaho Air Rules Section 210 (compliance with Emissions Screening Levels [ELs] or Acceptable Ambient Concentrations listed in Idaho Air Rules Section 585 and 586).

Types of permits requiring a NAAQS compliance demonstration are PTCs (Idaho Air Rules Section 200) and Tier II operating permits (Idaho Air Rules Section 400). All emission sources at the facility except for exempt sources under Idaho Air Rules Section 220-223, fugitive sources, and intermittent sources such as emergency generators will be included in the modeling analysis.

Additional discussion regarding the specifics of the proposed air dispersion modeling analysis are provided in the modeling protocol in Appendix E. Modeling results will be provided following approval of the modeling protocol.

Appendix A

Area Maps and Process Flow Diagram

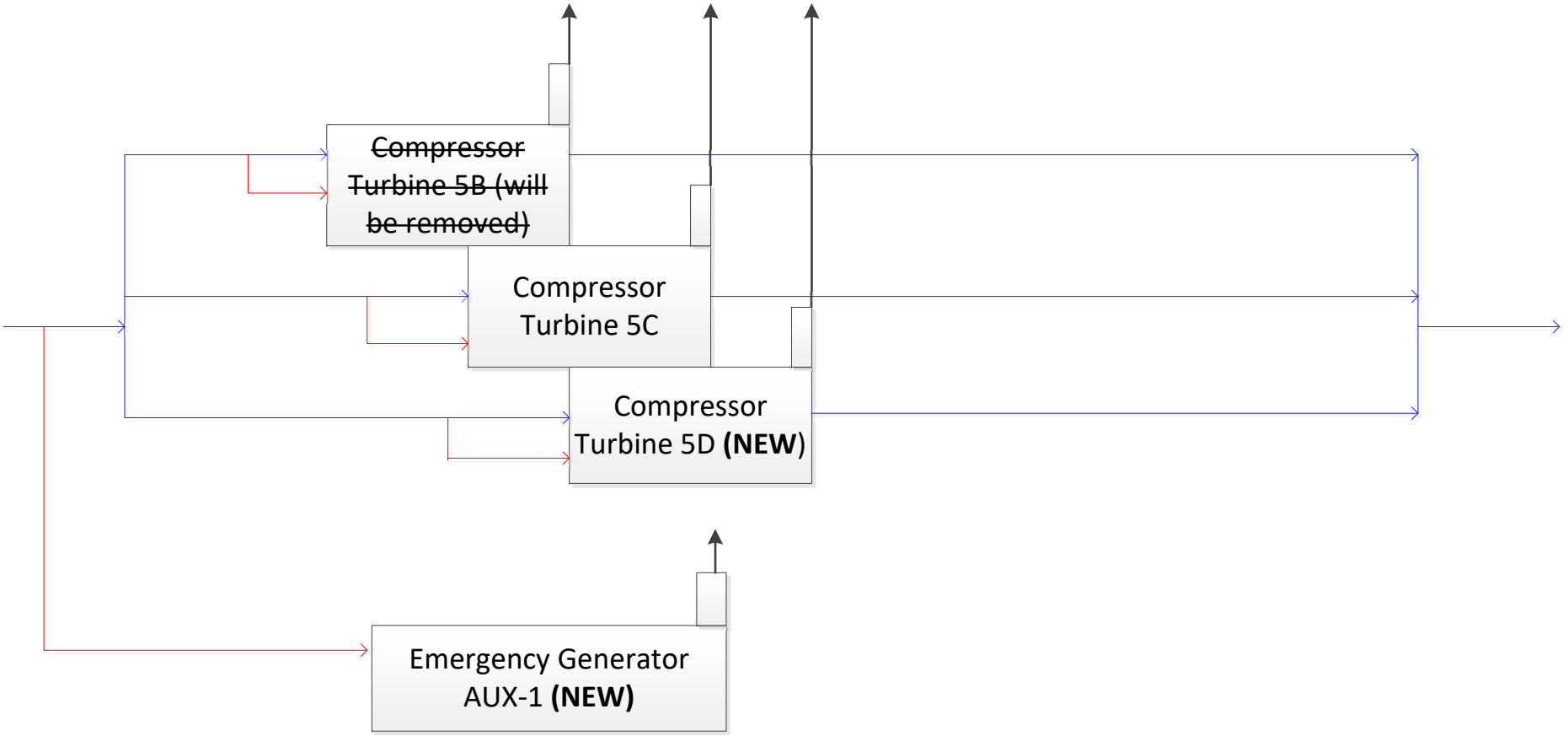


Gas Transmission Northwest, LLC – Compressor Station 5	WENCK Responsive partner. Exceptional outcomes.	May 2020
Map		



Gas Transmission Northwest, LLC – Compressor Station 5	WENCK Responsive partner. Exceptional outcomes.	May 2020
Plot Plan		

Gas Transmission Northwest, LLC
Compressor Station 5 Process Flow Diagram



Transmission Gas Stream
Fuel Gas
Emission Stream

Appendix B

Emission Calculations

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-1. Facility Total PTE

Source	Capacity	Annual Emissions (tpy)							
		NO_x	CO	CO_2e	$PM_{10}/PM_{2.5}$	VOC	SO_2	CH_2O	Total HAP
Unit 5D Solar Titan 130 Turbine[3]	21,087 hp (32 °F)	41.29	128.97	87,081	4.91	6.50	0.53	0.53	0.76
IA - Fuel Gas Heater	1.00 MMBtu/hr	0.43	0.36	513	0.03	0.02	0.003	0.0003	0.01
IA - Space Heaters	0.27 MMBtu/hr	0.12	0.10	138	0.01	0.01	0.001	0.0001	0.002
AUX-1 Caterpillar G3512 Emergency Generator	1,827 hp	2.01	4.03	382	0.03	1.01	0.002	0.2618	0.325
Equipment Leaks (fugitive emissions)[1]				17,948		6.52			
Venting				1,339		0.49			
Proposed Facility PTE[2]		43.85	133.45	89,454	4.98	8.03	0.54	0.79	1.10
Unit 5C Cooper Coberra 6000 Turbine	35,000 hp	197.03	142.79	156,885	3.01	3.07	3.81	0.95	1.38
Lube Oil Tanks (x4)[4]	2,785 gallons (total)					0.001			
Equipment Leaks (fugitive emissions)[1]				23,845		8.66			
Existing Facility PTE		197.03	142.79	156,885	3.01	3.07	3.81	0.95	1.38
Total Facility PTE (Existing + Proposed)		240.88	276.24	246,338	7.99	11.09	4.35	1.74	2.48
PSD Major Source Threshold		250	250	n/a	250	250	250	n/a	n/a
Title V Threshold		100	100	100,000	100	100	100	10	25
Applicability		Title V	Title V	Title V	None, Natural Minor	None, Natural Minor	None, Natural Minor	None, Area Source	None, Area Source

1. Fugitive emissions are not part of PSD applicability analysis.
2. Excludes fugitive emissions (compressor stations are not one of the named source categories that include fugitive emissions).
3. Turbine emissions based on 200 Start up / shut down cycles per year, 200 low-load hours per year and 50 low-temperature hours per year.
4. There are four existing lube oil tanks at the facility. The sizes are: 60, 1050, 175 and 1500 gallons. The emissions calculations were based on all tanks at 1500 gallons.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-2. PSD Analysis

Source	Capacity	Annual Emissions (tpy)							
		NO_x	CO	CO_2e	$PM_{10}/PM_{2.5}$	VOC	SO_2	CH_2O	Total HAP
Unit 5D Solar Titan 130 Turbine[3]	21,087 hp (32 °F)	41.29	128.97	87,081	4.91	6.50	0.53	0.53	0.76
IA - Fuel Gas Heater	1.00 MMBtu/hr	0.43	0.36	513	0.03	0.02	0.003	0.0003	0.01
IA - Space Heaters	0.27 MMBtu/hr	0.12	0.10	138	0.01	0.01	0.001	0.0001	0.002
AUX-1 Emergency Generator	1,827 hp	2.01	4.03	382	0.03	1.01	0.002	0.2618	0.325
Equipment Leaks (fugitive emissions)[1]				17,948		6.52			
Venting				1,339		0.49			
Proposed Facility PTE[2]		43.85	133.45	89,454	4.98	8.03	0.54	0.79	1.10
Unit 5B Cooper Coberra 125	14,300 hp	62.64	111.85	6,201	0.40	0.28	0.40	0.13	0.18
Existing Emergency Generator	691 hp	0.14	0.02	3.96	3.38E-04	3.99E-03	1.99E-05	3.14E-03	4.29E-03
Baseline Actual Emissions		62.77	111.87	6,205	0.40	0.28	0.40	0.13	0.19
PTE - Baseline Actual Emissions		-18.92	21.59	83,248	4.59	7.75	0.14	0.66	0.91
PSD Modification Threshold		40	100	n/a	15/10	40	40	n/a	n/a
Trigger PSD Review?		No	No	n/a	No	No	No	n/a	n/a

1. Fugitive emissions are not part of PSD applicability analysis.
2. Excludes fugitive emissions (compressor stations are not one of the named source categories that include fugitive emissions).
3. Turbine emissions based on 200 Start up / shut down cycles per year, 200 low-load hours per year and 50 low-temperature hours per year.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-3. TAPS Analysis for Proposed Modeled Sources

Pollutant	CAS No.	Source Emissions Rate (lb/hr)				Screening Emission Levels (EL) (lb/hr)[1]	Modeling Required? (Yes or No)[3]
		Unit 5D	Unit 5C	Fuel Gas Heater	Total		
Lead	7439-92-1	-	-	4.90E-07	4.90E-07	-	No
2-Methylnaphthalene	91-57-6	-	-	2.35E-08	2.35E-08	-	No
3-Methylchloranthrene	56-49-5	-	-	1.76E-09	1.76E-09	2.50E-06	No
7,12-Dimethylbenz(a)anthracene	NA	-	-	1.57E-08	1.57E-08	1.33E-01	No
1,3-Butadiene	106-99-0	7.30E-05	1.32E-04	-	2.05E-04	2.40E-05	Yes
Acenaphthene	83-32-9	-	-	1.76E-09	1.76E-09	-	No
Acenaphthylene	203-96-8	-	-	1.76E-09	1.76E-09	-	No
Acetaldehyde	75-07-0	6.79E-03	1.22E-02	-	1.90E-02	3.00E-03	Yes
Anthracene	120-12-7	-	-	2.35E-09	2.35E-09	-	No
Acrolein	107-02-8	1.09E-03	1.96E-03	-	3.04E-03	1.70E-02	No
Benz(a)anthracene	56-55-3	-	-	1.76E-09	1.76E-09	-	No
Benzene	71-43-2	2.04E-03	3.67E-03	2.06E-06	5.71E-03	8.00E-04	Yes
Benzo(a)pyrene	50-32-8	-	-	1.18E-09	1.18E-09	2.00E-06	No
Benzo(b)fluoranthene	205-99-2	-	-	1.76E-09	1.76E-09	-	No
Benzo(g,h,i)perylene	191-24-2	-	-	1.18E-09	1.18E-09	-	No
Benzo(k)fluoranthene	205-82-3	-	-	1.76E-09	1.76E-09	-	No
Chrysene	218-01-9	-	-	1.76E-09	1.76E-09	-	No
Dibenzo(a,h)anthracene	53-70-3	-	-	1.18E-09	1.18E-09	-	No
Dichlorobenzene	25321-22-6	-	-	1.18E-06	1.18E-06	-	No
Ethylbenzene	100-41-4	5.43E-03	9.79E-03	-	1.52E-02	2.90E+01	No
Fluoranthene	206-44-0	-	-	2.94E-09	2.94E-09	-	No
Fluorene	86-73-7	-	-	2.75E-09	2.75E-09	-	No
Formaldehyde	50-00-0	1.21E-01	2.17E-01	7.35E-05	3.38E-01	5.10E-04	Yes
Hexane	110-54-3	-	-	1.76E-03	1.76E-03	1.20E+01	No
Indeno(1,2,3-cd)pyrene	193-39-5	-	-	1.76E-09	1.76E-09	-	No
Methanol	67-56-1	-	-	-	0.00E+00	1.73E+01	No
Naphthalene	91-20-3	2.21E-04	3.98E-04	5.98E-07	6.19E-04	3.33E+00	No
PAH	NA	3.74E-04	6.73E-04	-	1.05E-03	9.10E-05	Yes
Phenanthrene	85-01-8	-	-	1.67E-08	1.67E-08	-	No
Phenol	108-95-2	-	-	-	0.00E+00	1.27E+00	No
Propylene Oxide	75-56-9	4.92E-03	8.87E-03	-	1.38E-02	3.20E+00	No
Pyrene	129-00-0	-	-	4.90E-09	4.90E-09	-	No
Toluene	108-88-3	2.21E-02	3.98E-02	3.33E-06	6.18E-02	2.50E+01	No
Xylene	1330-20-7	1.09E-02	1.96E-02	-	3.04E-02	2.90E+01	No
Arsenic	7440-38-2	-	-	1.96E-07	1.96E-07	1.50E-06	No
Beryllium	744-43-0-9	-	-	1.18E-08	1.18E-08	-	No
Cadmium	7440-43-9	-	-	1.08E-06	1.08E-06	3.70E-06	No
Chromium	7440-47-3	-	-	1.37E-06	1.37E-06	3.30E-02	No
Cobalt	7440-48-4	-	-	8.24E-08	8.24E-08	3.30E-03	No
Nickel	7440-02-0	-	-	2.06E-06	2.06E-06	2.70E-05	No
Selenium	7782-49-2	-	-	2.35E-08	2.35E-08	1.30E-02	No

1. Screening emissions levels (EL) are from Idaho Administrative Code 58.01.01 - Rules for the Control of Air Pollutation in Idaho Sections 585 and 586

2. According to Section 586 of IDAPA 58.01.01 the following PAHs shall be considered together as one TAP: benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indenol(1,2,3,-cd)pyrene.

3. The emergency generator and space heaters are considered exempt sources from modeling under Idaho Air Rules Section 220-223. Therefore, if a pollutant is above the EL but is only emitted by the emergency generator or space heaters it was excluded from the modeling analysis.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-4. Unit 5D Solar Titan 130 Turbine

Horsepower	21,087	hp (32 °F)
Brake Specific Fuel Consumption	7253	Btu/Bhp-hr (LHV, 32 °F)
Total Heat Input	152.96	MMBtu/hr (LHV, 32 °F)
	169.79	MMBtu/hr (HHV, 32 °F)[3]
Maximum Heat Input (at 0 °F)	161.02	MMBtu/hr (LHV, 0 °F)
	178.73	MMBtu/hr (HHV, 0 °F)[3]
Operating Hours	8760	hr/yr
Natural Gas Heat Content	1020	Btu/scf
Fuel Consumption	1458.16	MMscf/yr (based on 32 °F)
	175,227.6	scf/hr (based on 0 °F)
Quantity	1	

Pollutant	Emission Factor			Emission Rate		Emission Factor Reference
	ppmvd@15%O_2	lb/MMBtu		lb/hr[1]	ton/yr[2]	
NO_x	15.00	0.060	LHV	9.18	41.29	Vendor Data
CO	25.00	0.061	LHV	9.32	128.97	Vendor Data
CO_2e		117.1	HHV	19,882	87,081	40 CFR 98 Subpart C
PM_{10}		0.0066	HHV	1.12	4.91	AP-42 Table 3.1-2a (4/00)
$PM_{2.5}$		0.0066	HHV	1.12	4.91	AP-42 Table 3.1-2a (4/00)
VOC	5.00	0.007	LHV	1.07	6.50	Vendor Data (20% of UHC)[4]
SO_2 (Maximum Hourly)		0.0571	HHV	9.69		20 grains S / 100 scf
SO_2 (Average Annual)		0.000714	HHV		0.53	0.25 grains S / 100 scf
Formaldehyde		0.00071	HHV	0.12	0.53	AP-42 Table 3.1-3 (4/00)
Total HAPs		0.00103	HHV	0.17	0.76	AP-42 Table 3.1-3 (4/00)

1. Maximum hourly emission rate based on normal operation at 32°F. Heat input, fuel consumption, and emissions increase as temperature decreases, and for the purpose of this application, hourly emissions are characterized by Solar emissions data for 32°F.

2. Annual emission rate based on combination of potential operating modes as provided on following page for NOx, CO, and VOC. The operating modes are 200 hours at low load (<40% load), 50 hours or low temperature (<0°F) and 200 startups and shutdowns per year. The remainder of the hours per year are based on emissions at normal load (32°F). All other pollutants based on horsepower and brake specific fuel consumption at 32°F.

3. HHV heat input based on HHV=1.11*LHV

4. VOC based on 20% of vendor data for unburned hydrocarbon.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-5. Unit 5D - Solar Titan 130 - Emission Rates

Emission Rates per Operating Mode

Operating Mode	Units	NO_x	CO	VOC
Normal Load @ 32°F[1]	lb/hr	9.18	9.32	1.07
Low Temp (<0 °F)[1]	lb/hr	9.69	9.83	1.12
Low-Load (<50%)[2]	lb/hr	20.97	850.77	9.72
Startup/ Shutdown[3]	lb/event	2.00	43.00	10.00

1. Based on data from Solar Titan 130 Compressor Set Predicted Emission Performance data sheet and the following concentrations:
   15 ppm NOx; 25 ppm CO; 5 ppm VOC
2. For the purpose of calculating potential annual emissions, non-startup/shutdown operation at <50% load is based on emissions data provided by Solar for 40% load.
3. Based on data from Solar PIL170 for SoLoNOx Titan 130 23502S CS/MD Application Nominal Start-up and Shutdown, Natural Gas Fuel, Production Units with Enhanced Emissions Control.

Potential Annual Emissions Per Turbine

Operating Mode	Operating Time[1]		NO_x	CO	VOC
	Cycles	hr/yr	ton/yr	ton/yr	ton/yr
Normal Load @ 32 °F		8443	38.75	39.35	4.50
Low Temp (<0 °F)[2]		50	0.24	0.25	0.03
Low-Load (<40%)		200	2.10	85.08	0.97
Startup/ Shutdown	200	67	0.20	4.30	1.00
Total		8,760	41.29	128.97	6.50

1. Startup/Shutdown cycles based on 20 minute cycle time. Based on Startup/Shutdown event time of 10 minutes each as listed in Solar PIL 170 (Revision 5, June 13, 2012)

Emission Rates During Normal Operation (g/hp-hr)[1]

Emission Point ID / Model	NO_x	CO	VOC[2]	SO_2[3]	PM_{10} / $PM_{2.5}$	CH_2O
Solar Titan 130	0.20	0.20	0.02	0.21	0.02	0.003

1. Based on vendor performance data; values in italics based on AP-42 emission factors.
2. VOC is based on 20 percent of unburned hydrocarbons per Solar Product Information Letter 168.
3. Conservatively based on 20 grains sulfur per 100 standard cubic feet of natural gas for maximum short-term emissions.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-6. Unit 5D Solar Titan 130 Turbine

Number of Pneumatic Actuators:	2	per turbine
Pneumatic Actuator Vent Rate:	3	scf/hr/actuator
Number of Startup/Shutdown Cycles:	200	per turbine per year
Electric Starter Emissions per Startup:	0	scf
Blowdown Emissions per Shutdown:	4,651	scf
Number of Turbines	1	
Number of Dry Seals:	2	per turbine
Dry Seal Vent Rate:	0.5	scf/min/seal
Emergency Blowdown Events per Year:	1	per year
Blowdown Emissions:	4,651	scf per event
Blowdown Emissions - Balance of Station:	1,193,698	scf per event
Blowdown Emissions per Event:	1,198,349	scf per event
Blowdown Emissions per Year:	1,198,349	scf
Annual Operating Hours:	8,760	

Component	Emission Rate								
	Total	CH_4[2]	CO_2[2]	CH_4[3]	CO_2[3]	CH_4	CO_2	CO_2e[4]	VOC[6]
Continuous During Operation	**scf/hr**	**scf/hr**	**scf/hr**	**lb/hr**	**lb/hr**	**ton/yr**	**ton/yr**	**ton/yr**	**ton/yr**
Pneumatic Actuator (Total for number of units)	6.00	5.61	0.05	0.24	0.01	1.04	0.03	26.01	0.01
Dry Seals (Total for number of units)	60.00	56.06	0.52	2.37	0.06	10.39	0.27	260.10	0.09
Intermittent During Startup/Shutdown	**scf/event**	**scf/event**	**scf/event**	**lb/event**	**lb/event**	**ton/yr**	**ton/yr**	**ton/yr**	**ton/yr**
Pneumatic Starter (Total for number of units)[1]	0	0	0	0	0	0	0	0	0.00
Blowdowns (Total for number of units)[1,5]	4,651	4,346	41	184	5	18	0	460	0.17
Emergency Blowdown	**scf/year**	**scf/year**	**scf/year**			**ton/yr**	**ton/yr**	**ton/yr**	**ton/yr**
Blowdown Emissions	1,198,349	1,119,652	10,474			23.70	0.22	593	0.22
							Total:	1,339	0.49

1. Emission rates per event instead of per hour
2. CH_4 and CO_2 emission rates based on 93.4329 vol% CH_4 and 0.8740 vol% CO_2 in natural gas. Volume fractions obtained from a gas
3. Conversion based on densities of GHG as provided in 40 CFR 98.233(v)
4. Based on 40 CFR 98 Subpart A Global Warming Potentials
5. Conservative estimate based on 1 blowdown per shutdown. It is not expected that a blowdown will occur after each shutdown.
6. Based on a 0.0091 ratio of VOC to methane as calculated from gas composition.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-7. Unit AUX-1 Caterpillar G3512 Emergency Generator

Horsepower	1,827	hp
Brake Specific Fuel Consumption	7,143	Btu/Bhp-hr (HHV)
	6,494	Btu/Bhp-hr (LHV)
Total Heat Input	13.05	MMBtu/hr
Operating Hours	500	hr/yr
Natural Gas Heat Content	1,020	Btu/scf
Fuel Consumption	6.40	MMscf/yr
	12,795	scf/hr

Pollutant	Emission Factor			Emission Rate		Emission Factor Reference
	g/bhp-hr	ppm @ 15% O2	lb/MMBtu	lb/hr	ton/yr	
NO_x	2.00	160		8.06	2.01	NSPS Subpart JJJJ Limitation
CO	4.00	540		16.11	4.03	NSPS Subpart JJJJ Limitation
CO_2e			117.1	1,528	382	40 CFR 98 Subpart C
PM_{10}			0.010	0.13	0.03	AP-42 Table 3.2-2 (7/00) - 4SLB
$PM_{2.5}$			0.010	0.13	0.03	AP-42 Table 3.2-2 (7/00) - 4SLB
VOC	1.00	86		4.03	1.01	NSPS Subpart JJJJ Limitation
SO_2 (Maximum Hourly)			0.0571	0.75		20 grains S / 100 scf
SO_2 (Average Annual)			0.000714		0.002	0.25 grains S / 100 scf
Formaldehyde[1]	0.26		0.080	1.05	0.26	Vendor Data
Total HAPs			0.100	1.30	0.33	AP-42 Table 3.2-2 (7/00) - 4SLB

1. Emission factors from vendor specification sheet for Caterpillar gas engine G3512 (Data Generated by Gas Engine Data Master, Version 6.01.00.)

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-8. Fugitive Emissions from Leaks - Solar Titan 130 Turbine 5D

Number of Compressors: 1
Annual Operating Hours: 8,760

	Average Number of Leaking Components[1]	Emission Factor[2]	Total Emission Rate (1 compressors)								
			Total	CH_4[3]	CO_2[3]	CH_4[4]	CO_2[4]	CH_4	CO_2	CO_2e[5]	VOC[6]
Component	component leaks / compressor	scf/hr / component	scf/hr	scf/hr	scf/hr	lb/hr	lb/hr	ton/yr	ton/yr	ton/yr	ton/yr
Compressor Service											
Valve	142	14.84	2107.28	1968.89	18.42	83.34	2.14	365.03	9.35	9135.16	3.32
Connector	300	5.59	1677.00	1566.87	14.66	66.32	1.70	290.50	7.44	7269.87	2.64
Open-Ended Line	14	17.27	241.78	225.90	2.11	9.56	0.25	41.88	1.07	1048.13	0.38
Pressure Relief Valve	2	39.66	79.32	74.11	0.69	3.14	0.08	13.74	0.35	343.86	0.12
Meter	1	19.33	19.33	18.06	0.17	0.76	0.02	3.35	0.09	83.80	0.03
Non-Compressor Service											
Valve	0.60	6.42	3.85	3.60	0.03	0.15	0.00	0.67	0.02	16.70	0.01
Connector	0.82	5.71	4.68	4.37	0.04	0.19	0.00	0.81	0.02	20.30	0.01
Open-Ended Line	0.59	11.27	6.65	6.21	0.06	0.26	0.01	1.15	0.03	28.83	0.01
Pressure Relief Valve	0.12	2.01	0.24	0.23	0.00	0.01	0.000	0.04	0.001	1.05	0.00
Meter	0.01	2.93	0.03	0.03	0.00	0.001	0.000	0.01	0.0001	0.13	0.00
							Total:	717.18	18.38	17,948	6.52

1. Estimated component leaks per compressor based on project estimates.
2. Emission factors from 40 CFR 98 Subpart W Table W-3A.
3. CH_4 and CO_2 emission rates based on 93.4329 vol% CH_4 and 0.8740 vol% CO_2 in natural gas. Volume fractions obtained from a gas chromatograph located at the Stanfield Compressor Station in Oregon.
4. Conversion based on densities of GHG as provided in 40 CFR 98.233(v)
5. Based on 40 CFR 98 Subpart A Global Warming Potentials
6. Based on a 0.0091 ratio of VOC to methane as calculated from gas composition.

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-9. IA - Space Heaters (SH1 - 6 X 0.045 MMBtu/hr)

Total Heat Input	0.27	MMBtu/hr
Operating Hours	8,760	hr/yr
Natural Gas Heat Content	1,020	Btu/scf
Fuel Consumption	2.32	MMscf/yr
	265	scf/hr

Pollutant	Emission Factor		Emission Rate		Emission Factor Reference
	lb/MMscf	lb/MMBtu	lb/hr (all heaters)	ton/yr	
NO_x	100	0.098	0.03	0.12	AP-42 Table 1.4-1 (7/98)
CO	84	0.082	0.02	0.10	AP-42 Table 1.4-1 (7/98)
CO_2e		117.1	32	138	40 CFR 98 Subpart C
PM_{10}	7.6	0.007	0.00	0.01	AP-42 Table 1.4-2 (7/98)
$PM_{2.5}$	7.6	0.007	0.00	0.01	AP-42 Table 1.4-2 (7/98)
VOC	5.5	0.005	0.00	0.01	AP-42 Table 1.4-2 (7/98)
SO_2 (Maximum Hourly)		0.0571	0.02		20 grains S / 100 scf
SO_2 (Average Annual)		0.000714		0.001	0.25 grains S / 100 scf
Formaldehyde	0.075	0.00007	0.0000	0.0001	AP-42 Table 1.4-3 (7/98)
Total HAPs	1.89	0.00185	0.000	0.002	AP-42 Table 1.4-3 & 4 (7/98)

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table B-10. IA - Fuel Gas Heater

Heat Input	1.00	MMBtu/hr
Operating Hours	8,760	hr/yr
Natural Gas Heat Content	1,020	Btu/scf
Fuel Consumption	8.59	MMscf/yr
	980	scf/hr

Pollutant	Emission Factor		Emission Rate		Emission Factor Reference
	lb/MMscf	lb/MMBtu	lb/hr	ton/yr	
NO_x	100	0.098	0.10	0.43	AP-42 Table 1.4-1 (7/98)
CO	84	0.082	0.08	0.36	AP-42 Table 1.4-1 (7/98)
CO_2e		117.1	117	513	40 CFR 98 Subpart C
PM_{10}	7.6	0.007	0.01	0.03	AP-42 Table 1.4-2 (7/98)
$PM_{2.5}$	7.6	0.007	0.01	0.03	AP-42 Table 1.4-2 (7/98)
VOC	5.5	0.005	0.01	0.02	AP-42 Table 1.4-2 (7/98)
SO_2 (Maximum Hourly)		0.0571	0.06		20 grains S / 100 scf
SO_2 (Average Annual)		0.000714		0.003	0.25 grains S / 100 scf
Formaldehyde	0.075	0.00007	0.0001	0.0003	AP-42 Table 1.4-3 (7/98)
Total HAPs	1.89	0.00185	0.002	0.01	AP-42 Table 1.4-3 & 4 (7/98)

Appendix C

Unit 5B and Emergency Generator Baseline Actual Emissions

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table C-1. Unit 5B Cooper Rolls Coberra - Baseline Emissions

Emission Unit ID	**5B**			
Description of Unit	Cooper Rolls Coberra			
Manufacturer	Cooper			
Date of Construction/Modification	1970			
Fuel Used	Natural Gas			
Maximum Higher Heating Value (HHV)	1,020	Btu/scf		
Rated Horsepower (hp)	14,300	hp		
Heat Input (MMBtu/hr)	173.40	MMBtu/hr		
Maximum Hourly Fuel Consumption	170,000	scf/hr		
Control Device	N/A			
Annual Hours of Operation	8,760	hr/yr		
Annual Fuel Consumption	1,489.20	MMscf/yr		
Baseline Actual Hours	2631.75	hr/yr	Baseline Period	May 17 - Apr 19
Baseline Actual Fuel Consumption	345.64	MMscf/yr	Baseline Period	May 17 - Apr 19
Baseline Actual Fuel Consumption	352,553.31	MMBtu/yr		

Emission Factors:

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source
NOx	0.28	lb/1000 scf	a
CO	85.00	lb/hr	a
NM/NE VOC	1.60	lb/hr	a
PM10	2.29	lb/MMscf	a
PM2.5	2.29	lb/MMscf	a
SO2	2.90	lb/MMscf	a

[a] Based on Tier I Operating Permitted emission rates.

Baseline Actual Emissions:

Pollutant	Emission Rate (lb/hr)	Calculation Methodology	Baseline Actual Emissions [d] (ton/yr)
NOx	47.60	c	62.6
CO	85.00	b	111.8
NM/NE VOC	1.60	b	0.3
PM10	0.39	c	0.4
PM2.5	0.39	c	0.396
SO2	0.49	c	0.396

[b] Emission Rate (lb/hr) = (Emission Factor lb/hr)

[c] Emission Rate (lb/hr) = (Emission Factor lb/MMscf) * (Max Annual Fuel Consumption MMscf/yr) / (Annual Hours of Operation hr/yr)

[d] Emission Rate (ton/yr) = (Emission Rate lb/hr) * (24-month average baseline actual hr/yr) / (2000 lb/ton)

HAP Calculated Emissions:

Pollutant	Emission Factor (lb/MMBtu)[e]	Baseline Actual Emissions (lb/hr)[f]	Baseline Actual Emissions (tons/yr)[g]
HAPs:			
1,3-Butadiene	4.3E-07	7.46E-05	7.58E-05
Acetaldehyde	4.0E-05	6.94E-03	7.05E-03
Acrolein	6.4E-06	1.11E-03	1.13E-03
Benzene	1.2E-05	2.08E-03	2.12E-03
Ethylbenzene	3.2E-05	5.55E-03	5.64E-03
Formaldehyde	7.1E-04	1.23E-01	1.25E-01
Naphthalene	1.3E-06	2.25E-04	2.29E-04
PAH	2.2E-06	3.81E-04	3.88E-04
Propylene Oxide	2.9E-05	5.03E-03	5.11E-03
Toluene	1.3E-04	2.25E-02	2.29E-02
Xylene	6.4E-05	1.11E-02	1.13E-02
Total HAP	**1.03E-03**	**0.18**	**0.18**

[e] AP-42 Table 3.1-3 "Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines" (4/00).

[f] Emission Rate (lb/hr) = (Emission Factor, lb/MMBtu) * (Max Fuel Consumption, scf/hr) * (Maximum HHV, Btu/scf) * (MM/1,000,000)

[g] Emission Rate (ton/yr) = (Emission Rate, lb/hr) * (Annual Hours of Operation, hrs/yr) * (1 ton/2000 lb)

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table C-1. Unit 5B Cooper Rolls Coberra - Baseline Emissions

Emission Unit ID **5B**
Description of Unit Cooper Rolls Coberra

Baseline Actual Greenhouse Gas (GHG) Calculated Emissions:

Pollutant	Uncontrolled Emission Factor	Factor Units	Emissions (lb/hr)	Baseline Actual Emissions (TPY)	Global Warming Potential (GWP)	CO2e Emissions (lb/hr)	CO2e Emissions (TPY)
CO_2	53.06	kg CO_2/MMBtu	4707.85	6194.94	1	4707.85	6194.94
CH_4	0.001	kg CH_4/MMBtu	0.09	0.12	25	2.22	2.92
N_2O	0.0001	kg N_2O/MMBtu	0.01	0.01	298	2.64	3.48
TOTAL GHGs	--	--	**4707.94**	**6195.07**	--	--	--
TOTAL GHGs (CO_2e)	--	--	--	--	--	**4712.71**	**6201.34**

Based on 40 CFR 98 Subpart C, 98.33(a)(1)(i), Tier 1 Methodology, Equation C-1 and using source specific heat input.

GHG Emissions (lb/hr) = EF_{GHG} (kg/MMBtu) * 2.204623 lb/kg * Source Specific Heat Input (MMbtu/hr)
GHG Emissions (TPY) = GHG Emissions (lb/hr) * Annual Operating Hours (hr/yr) * 1 Ton/2000 lb
CO_2e Emissions (TPY) = Σ (GHG Emissions (tpy) * GWP)

Where:

EF_{GHG} = Average) and Table C-2 for CH_4 and N_2O (Natural Gas) of 40 CFR Part 98, Subpart C (kg/MMBtu)
Heat Input = Btu/hp-hr x Site-rated hp x (1 MMBtu/1,000,000 Btu) = MMBtu/hr
GWP = Global Warming Potentials, 40 CFR 98, Subpart A, Table A-1

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table C-2. Caterpillar CTP00249 Emergency Generator - Baseline Emissions

Emission Unit ID	**NA**	
Description of Unit	Caterpillar G3516, natural gas-fired generator	
Manufacturer	Caterpillar	
Date of Construction/Modification		
Stroke Cycle	4-Stroke	
Type of Burn	Lean-Burn	
Fuel Used	Natural Gas	
Maximum Higher Heating Value (HHV)	1,020	Btu/scf
Rated Horsepower (hp)	691	hp
Heat Input (MMBtu/hr)	1.76	MMBtu/hr
Control Device	N/A	
Annual Hours of Operation	500	hr/yr
Baseline Actual Hours	38.50	May 17 - Apr 19
Baseline Actual Fuel Consumption	67.64	MMBtu/yr

Emission Factors:

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source
NOx	4.08E+00	lb/MMBtu	a
CO	5.57E-01	lb/MMBtu	a
NM/NE VOC	1.18E-01	lb/MMBtu	a
PM10	9.99E-03	lb/MMBtu	a
PM2.5	9.99E-03	lb/MMBtu	a
SO2	5.88E-04	lb/MMBtu	a

[a] AP-42 Table 3.2-2 "Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines" (7/00). To be conservative, NOx EF is based on 90-105% Load; CO EF is based on <90% Load. PM10 and PM2.5 are both the sum of PM (condensable) and PM (filterable).

POTENTIAL EMISSIONS:

Pollutant	Emission Rate (lb/hr)	Calculation Methodology	Baseline Actual Emissions [c] (ton/yr)
NOx	7.17	b	0.14
CO	0.98	b	0.02
NM/NE VOC	0.21	b	0.004
PM10	0.02	b	3.38E-04
PM2.5	0.02	b	3.38E-04
SO2	1.03E-03	b	1.99E-05

Sample Calculation:

[b] Emission Rate (lb/hr) = (Emission Factor, lb/MMBtu) * (MMBtu/hr)

[c] Emission Rate (ton/yr) = (Emission Rate, lb/hr) * (Annual Operation, hrs/yr) * (1 ton/2000 lb)

HAP Calculated Emissions:

Pollutant	Emission Factor (lb/MMBtu)[d]	Baseline Actual Emissions (lb/hr)[e]	(tons/yr)[f]
HAPs:			
1,1,2,2-Tetrachloroethane	4.00E-05	7.03E-05	2.38E-06
1,1,2-Trichloroethane	3.18E-05	5.59E-05	1.89E-06
1,3-Butadiene	2.67E-04	4.69E-04	1.59E-05
1,3-Dichloropropene	2.64E-05	4.64E-05	1.57E-06
Acetaldehyde	8.36E-03	1.47E-02	4.97E-04
Acrolein	5.14E-03	9.03E-03	3.05E-04
Benzene	4.40E-04	7.73E-04	2.61E-05
Carbon Tetrachloride	3.67E-05	6.45E-05	2.18E-06
Chlorobenzene	3.04E-05	5.34E-05	1.81E-06
Chloroform	2.85E-05	5.01E-05	1.69E-06
Ethylbenzene	3.97E-05	6.97E-05	2.36E-06
Ethylene Dibromide	4.43E-05	7.78E-05	2.63E-06
Formaldehyde	5.28E-02	9.28E-02	3.14E-03
Methanol	2.50E-03	4.39E-03	1.49E-04
Methylene Chloride	2.00E-05	3.51E-05	1.19E-06
Naphthalene	7.44E-05	1.31E-04	4.42E-06
PAH	2.69E-05	4.73E-05	1.60E-06
Styrene	2.36E-05	4.15E-05	1.40E-06
Toluene	4.08E-04	7.17E-04	2.42E-05
Vinyl Chloride	1.49E-05	2.62E-05	8.85E-07
Xylene	1.84E-04	3.23E-04	1.09E-05
Total HAP	**7.22E-02**	**0.13**	**4.29E-03**

[d] AP-42 Table 3.2-2 "Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines" (7/00).

[e] Emission Rate (lb/hr) = (Emission Factor, lb/MMBtu) * (Rated Horsepower, hp) * (Heat Rate, Btu/bhp-hr) * (MM/1,000,000)

[f] Emission Rate (ton/yr) = (Emission Rate, lb/hr) * (Annual Hours of Operation, hrs/yr) * (1 ton/2000 lb)

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table C-2. Caterpillar CTP00249 Emergency Generator - Baseline Emissions

Emission Unit ID **NA**

Potential Greenhouse Gas (GHG) Calculated Emissions:

Pollutant	Uncontrolled Emission Factor	Factor Units	Emissions (lb/hr)	Emissions (TPY)	Global Warming Potential (GWP)	CO2e Emissions (lb/hr)	CO2e Emissions (TPY)
CO_2	53.06	kg CO_2/MMBtu	205.51	3.96	1	205.51	3.96
CH_4	0.001	kg CH_4/MMBtu	0.00	0.00	25	0.10	0.00
N_2O	0.0001	kg N_2O/MMBtu	0.00	0.00	298	0.12	0.00
TOTAL GHGs	--	--	**205.52**	**3.96**	--	--	--
TOTAL GHGs (CO_2e)	--	--	--	--	--	**205.73**	**3.96**

Based on 40 CFR 98 Subpart C, 98.33(a)(1)(i), Tier 1 Methodology, Equation C-1 and using source specific heat input.

GHG Emissions (lb/hr) = EF_{GHG} (kg/MMBtu) * 2.204623 lb/kg * Source Specific Heat Input (MMbtu/hr)

GHG Emissions (TPY) = GHG Emissions (lb/hr) * Annual Operating Hours (hr/yr) * 1 Ton/2000 lb

CO_2e Emissions (TPY) = Σ (GHG Emissions (tpy) * GWP)

Where:

EF_{GHG} = Fuel-specific default CO_2, CH_4, or N_2O emission factors from Table C-1 for CO_2 (Natural gas - Weighted U.S.

Heat Input = Btu/hp-hr x Site-rated hp x (1 MMBtu/1,000,000 Btu) = MMBtu/hr

GWP = Global Warming Potentials, 40 CFR 98, Subpart A, Table A-1

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table C-3. Unit 5B Cooper Rolls Coberra - Monthly Baseline Fuel Use

Month	Unit 5B Monthly Fuel Use (MMCF)	Highest 24-Month Annual Average Rolling Total (MMCF/YR)
Mar-16	18.79	
Apr-16	11.06	
May-16	29.41	
Jun-16	38.35	
Jul-16	15.59	
Aug-16	22.55	
Sep-16	11.96	
Oct-16	2.06	
Nov-16	81.42	
Dec-16	4.27	
Jan-17	4.9	
Feb-17	0.4	
Mar-17	3.9	
Apr-17	2.9	
May-17	37.6	
Jun-17	42.8	
Jul-17	3.9	
Aug-17	16.0	
Sep-17	19.1	
Oct-17	71.2	
Nov-17	2.4	
Dec-17	6.6	
Jan-18	0.0	
Feb-18	0.2	223.6
Mar-18	0.0	214.2
Apr-18	0.0	208.7
May-18	0.0	194.0
Jun-18	0.0	174.8
Jul-18	62.6	198.3
Aug-18	32.1	203.1
Sep-18	98.2	246.2
Oct-18	81.2	285.8
Nov-18	13.7	251.9
Dec-18	56.6	278.0
Jan-19	25.6	288.4
Feb-19	26.5	301.4
Mar-19	68.9	334.0
Apr-19	26.2	345.6
May-19	18.2	335.9
Jun-19	5.3	317.2
Jul-19	8.5	319.5
Aug-19	41.0	332.0
Sep-19	3.4	324.1
Oct-19	0.4	288.7
Nov-19	2.4	288.7
Dec-19	2.0	286.4
Jan-20		286.4
Feb-20		286.3
Mar-20		286.3
Maximum 24-Month Annual Baseline Period Emissions (MMCF/YR)		345.64
Baseline Period Dates		May 17 - Apr 19

Gas Transmission Northwest (GTN)
Compressor Station 5
Permit to Construct/Tier I Operating Permit Signifcant Modification
May 2020

Table C-4. Unit 5B Cooper Rolls Coberra - Monthly Baseline Hours of Operation

Month	Unit 5B Monthly Hours of Operation (HR/MO)	Highest 24-Month Annual Average Rolling Total (HR/YR)	Emer Gen Monthly Hours of Operation - Emergency (HR/MO)	Emer Gen Monthly Hours of Operation - Maintenance (HR/MO)	Emer Gen Monthly Hours of Operation - Total (HR/MO)	Highest 24-Month Annual Average Rolling Total (HR/YR)
Mar-16	137.50		0.0	2.0	2.0	
Apr-16	80.75		0.0	1.0	1.0	
May-16	239.50		1.0	1.0	2.0	
Jun-16	288.25		0.0	1.0	1.0	
Jul-16	133.25		0.0	0.5	0.5	
Aug-16	177.00		0.0	2.5	2.5	
Sep-16	113.50		0.0	1.0	1.0	
Oct-16	14.50		0.0	1.0	1.0	
Nov-16	620.50		0.0	2.0	2.0	
Dec-16	30.50		0.0	1.0	1.0	
Jan-17	36.0		0.0	0.0	0.0	
Feb-17	2.8		0.0	0.5	0.5	
Mar-17	25.5		0.0	4.0	4.0	
Apr-17	21.5		2.5	0.5	3.0	
May-17	278.8		5.0	0.5	5.5	
Jun-17	330.5		2.0	0.5	2.5	
Jul-17	31.5		3.0	1.5	4.5	
Aug-17	129.3		2.5	0.0	2.5	
Sep-17	147.5		6.0	1.0	7.0	
Oct-17	529.5		15.0	1.0	16.0	
Nov-17	15.5		1.5	0.5	2.0	
Dec-17	45.5		0.5	0.5	1.0	
Jan-18	0.0		2.0	0.0	2.0	
Feb-18	1.3	1715.1	1.5	0.0	1.5	33.0
Mar-18	0.0	1646.4	3.0	0.0	3.0	33.5
Apr-18	1.0	1606.5	2.5	0.0	2.5	34.3
May-18	2.5	1488.0	2.5	0.5	3.0	34.8
Jun-18	200.5	1444.1	0.5	0.0	0.5	34.5
Jul-18	442.5	1598.8	5.5	0.0	5.5	37.0
Aug-18	230.3	1625.4	2.5	0.0	2.5	37.0
Sep-18	694.5	1915.9	3.0	0.0	3.0	38.0
Oct-18	574.3	2195.8	1.5	0.0	1.5	38.3
Nov-18	96.5	1933.8	2.0	0.0	2.0	38.3
Dec-18	405.5	2121.3	1.0	0.0	1.0	38.3
Jan-19	186.5	2196.5	0.0	0.5	0.5	38.5
Feb-19	210.5	2300.4	0.0	0.5	0.5	38.5
Mar-19	501.8	2538.5	0.0	0.5	0.5	36.8
Apr-19	208.0	2631.8	0.0	0.5	0.5	35.5
May-19	146.8	2565.8	0.0	0.5	0.5	33.0
Jun-19	17.8	2409.4	0.0	0.5	0.5	32.0
Jul-19	65.5	2426.4	0.0	0.5	0.5	30.0
Aug-19	333.3	2528.4	0.0	0.5	0.5	29.0
Sep-19	34.0	2471.6	0.0	0.5	0.5	25.8
Oct-19	5.0	2209.4	0.0	0.5	0.5	18.0
Nov-19	17.0	2210.1	0.0	0.5	0.5	17.3
Dec-19	16.5	2195.6	0.0	0.5	0.5	17.0
Jan-20		2195.6				16.0
Feb-20		2195.0				15.3
Mar-20		2195.0				13.8
Maximum 24-Month Annual Baseline Period Hours (HR/YR)		2631.8				38.5
Baseline Period Dates		May 17 - Apr 19				May 17 - Apr 19

Appendix D

PTC/Tier I Significant Modification Application Forms

Idaho Department of Environmental Quality
Air Quality Division
Stationary Source Program

Tier I Operating Permit Application Completeness Checklist

This checklist is designed to aid the applicant in submitting a complete Tier I permit application. In addition to the items in this checklist, information requested by DEQ during review of the application should be provided in accordance with IDAPA 58.01.01.314.12 and IDAPA 58.01.01.315.

1. General Facility Information

☒ Complete and sign the Tier I Application and General Information Cover Sheet (Form GI)

2. Applicable Equipment-Specific Application Forms

☒ Complete all applicable equipment-specific applications forms. For all forms listed below, please visit DEQ's website at www.deq.idaho.gov/.

Control Devices
- Form AO (Afterburner/Oxidizer
- Form CA (Carbon Absorber)
- Form CYS (Cyclone Separator)
- Form ESP (Electrostatic Precipitator)
- Form BCE (Baghouse Control Equipment)
- Form SCE (Scrubber Control Equipment)

NA

Industrial Category Specific
- Form EU2 (Nonmetallic Mineral Processing Plant – fugitive dust only)
- Form HMAP (Hot-mix Asphalt Plant)
- Form CBP (Concrete Batch Plant)

Emissions Unit Specific
- Form EU0 (General Emissions Unit)
- Form EU1 (Industrial Engine)
- Form EU3 (Spray Paint Booth) NA
- Form EU4 (Cooling Towers) NA
- Form EU5 (Boilers) NA - The space heaters and fuel gas heater are considered insignificant activities under IDAPA 58.01.01.b.i.5.

Compliance Assurance Monitoring NA
- Form CAM (Compliance Assurance Monitoring). Refer to 40 CFR 64

Emissions Inventory
- Forms EI (Emissions Inventory Requirements & Forms)

Other Applicability Forms
- Form FRA (Federal Requirements Applicability)

3. Additional Required Information not Cover by Equipment-Specific Forms

☒ For equipment that is not covered by any of the above equipment-specific forms, the following applicable data are required.
- Plot Plan - Equipment Location Drawing - Equipment Description - Fuel and Burners Used
- Operating Schedule - Process Description - Process Flow Diagram - Process Rate
- Material Safety Data Sheets (MSDS) - Other data needed to process application

4. Applicable Requirements

☒ Cite and describe all applicable requirements affecting each emissions unit. Describe or reference all methods required by each applicable requirement for determining the compliance status of the emissions unit with the applicable requirement, including any applicable monitoring, recordkeeping and reporting requirements or test methods.

5. Obsolete Permit Conditions

☒ Review all existing permit conditions or past requirements that had either been completed prior to issuance of the Tier I operating permit or were required by the Tier I operating permit to have been completed before the Tier I operating permit issuance date. For each permit condition determined to be obsolete, thoroughly explain the decision to omit an obsolete permit condition in the statement of basis.

Tier I Operating Permit Application Completeness Checklist

6. Proposed Determination of Non-Applicability

NA ☒ Identify requirements for which the applicant seeks a determination of non-applicability and provide an explanation of why the requirement is not applicable to the Tier I source.

7. Alternative Operating Scenarios

NA ☒ Identify all requested alternative operating scenarios. Provide a detailed description of all requested alternative operating scenarios. Include all the information required by Section 314 that is relevant to the alternative operating scenario.

8. Compliance Certifications

☒ Provide a compliance certification regarding the compliance status of each emissions unit at the time the application is submitted to the DEQ that:

NA- Application is not for a Tier I Renewal Application

- Identifies all applicable requirements affecting each emissions unit.
- Certifies the compliance status of each emissions unit with each of the applicable requirements.
- Provides a detailed description of the method(s) used for determining the compliance status of each emissions unit with each applicable requirement, including a description of any monitoring, recordkeeping, reporting and test methods that were used. Also provide a detailed description of the method(s) required for determining compliance.
- Certifies the compliance status of the emissions unit with any applicable enhanced monitoring requirements.
- Certifies the compliance status of the emissions unit with any applicable enhanced compliance certification requirements.
- Provides all other information necessary to determining the compliance status of the emissions unit.
- Provide a schedule for submission of compliance certifications during the term of the Tier I operating permit. The schedule shall require compliance certifications to be submitted no less frequently than annually or more frequently if specified by the underlying applicable requirement or by the DEQ.

9. Compliance Plans

☒ Provide a compliance description as follows:

NA- See Report Text

- For each applicable requirement with which the emissions unit is in compliance, state that the emissions unit will continue to comply with the applicable requirement.
- For each applicable requirement that will become effective during the term of the Tier I operating permit that does not contain a more detailed schedule, state that the emissions unit will meet the applicable requirement on a timely basis.
- For each applicable requirement that will become effective during the term of the Tier I operating permit that contains a more detailed schedule, state that the emissions unit will comply with the applicable requirement on the schedule provided in the applicable requirement.
- For each applicable requirement with which the emission unit is not in compliance, state that the emissions unit will be in compliance with the applicable requirement by the time the Tier I operating permit is issued or provide a compliance schedule in accordance with Subsection 314.10.b.

10. Compliance Schedules

☒ All compliance schedules shall:

NA- Facility is in compliance

- Include a schedule of remedial measures leading to compliance, including an enforceable sequence of actions and specific dates for achieving milestones and achieving compliance.
- Incorporate the terms and conditions of any applicable consent order, judicial order, judicial consent decree, administrative order, settlement agreement or judgment.
- Be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.
- Provide a schedule for submission to the DEQ of periodic progress reports no less frequently than every six (6) months or at a more frequent period if one (1) is specified in the underlying applicable requirement or by the DEQ.

11. Trading Scenarios

NA ☒ Identify all requested trading scenarios, including alternative emissions limits (bubbles) authorized by Section 440.

NA ☒ Provide a detailed description of all requested trading scenarios. Include all the information required by

Tier I Operating Permit Application Completeness Checklist

Section 314 that is relevant to the trading scenario and all the information required by Section 440, if applicable. Emissions trades must comply with all applicable requirements.

NA ☒ Provide proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable and enforceable. Emissions trades involving emissions units for which the emissions are not quantifiable or for which there are no replicable procedures to enforce the emissions trade shall not be approved.

12. Insignificant Activities Based on Size or Production Rate

☒ Provide a list of units or activities that are insignificant on the basis of size or production rate. Refer to IDAPA 58.01.01.317.01.b and 40 CFR 70.5(c).

13. Acid Rain Program Requirements

NA ☒ For any affected units subject to the Acid Rain Program pursuant to 40 CFR 72.6, submit an Acid Rain Permit Application in accordance with 40 CFR 72, Subpart C.

14. Permit Shield Request

☒ A Tier I operating permit with a permit shield will identify rules that do not apply, and state that compliance with all conditions of the permit will be considered as compliance with all regulatory requirements in effect as of the date of permit issuance. A requirement identified in the permit as non-applicable is not enforceable by EPA, DEQ, or citizens. If a permit shield is being sought, describe the regulatory requirement that the facility is requesting a shield for and cite the rule reference and date of the rule version (e.g. IDAPA 58.01.01.860, 04/05/2000); explain the reason(s) for requesting a permit shield for each regulatory requirement; and indicate the length of time over which the permit shield should last.

15. Documents for Public Comment

☒ Copies of all compliance documents required by a Tier I operating permit, including but not limited to quality assurance plans, dust management plans, and operation and maintenance manuals, are to be included in the permit application for review during the public comment period.

16. Certification of Documents

☒ All documents, including but not limited to, application forms for permits to construct, application forms for operating permits, progress reports, records, monitoring data, supporting information, requests for confidential treatment, testing reports or compliance certifications submitted to the DEQ shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Refer to IDAPA 58.01.01.123.

17. DEQ Mailing Address

☒ Submit the certified Tier I operating permit application to the following address:

Department of Environmental Quality
Air Quality Division
Stationary Source Program Office
1410 North Hilton
Boise, ID 83706-1255

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

General Information - **Form GI**
04/23/19

Please see instructions on second page before filling out the form.

FACILITY AND PERMIT INFORMATION

1. Facility Name:	2. Facility ID Number:
Compressor Station 5	055-00033

3. Brief Project Description:	GTN is proposing to replace the existing combustion turbine Unit 5B and the existing emergency generator with a new Solar Titan 130 turbine and a new emergency generator.

4. Facility Contact Name:	5. Facility Contact Title:
Lacey Ivey	Principal Air Scientist
6. Facility Contact Telephone Number:	7. Facility Contact Email:
337-241-0686	lacey_ivey@tcenergy.com
8. Mailing address where permit will be sent (street/city/state/zip code):	9. Physical address of facility (if different than mailing address) (street/city/state/zip code):
700 Louisiana Street, Suite 700/Houston/TX/77002	2244 E. Seasons Road/Athol/ID/83801

10. County Facility is located	Kootenai	
11. Is the equipment portable?	■ No ☐ Yes	
12. NAICS codes	Primary NAICS: 486210	Secondary NAICS (if applicable):
13. Brief business description and principal product produced:	Transmission of natural gas via pipeline using compression derived from multiple turbine based sources.	
14. Describe any contiguous or adjacent facility this company owns or operates:	N/A	
15. Permit Application Type. Provide Permit Number for existing permit. For a PTC, an application fee is required.	■ Initial Permit to Construct (PTC) ☐ PTC Modification	PTC No. _____ Issued Date _____
	☐ Initial Tier II ☐ Tier II Modification ☐ Tier II Renewal	Tier II No. _____ Issued Date _____
	☐ Initial Tier I ☐ Tier I Administrative Amendment ☐ Tier I Minor Modification ■ Tier I Significant Modification ☐ Tier I Renewal	Tier I No. T1-2016.0024 Issued Date 05/02/2017

16. **For Tier I permitted facilities only:** If you are applying for a PTC then you must specify how the PTC will be incorporated into the Tier I permit.	☐ Incorporate PTC at the time of Tier I renewal (IDAPA 58.01.01.209.05.a) ■ Co-process PTC with Tier I Modification (IDAPA 58.01.01.209.05.b) ☐ Administrative amend the Tier I to incorporate PTC upon applicant's request (IDAPA 58.01.01.209.05.c)
17. ■ Check here to request facility draft permit before final issuance.	
18. ☐ Check here to request a permit hand-off meeting.	

Certification of Truth, Accuracy, and Completeness (by Responsible Official)
I hereby certify that based on information and belief formed after reasonable inquiry, the statements and information contained in this and any attached and/or referenced document(s) are true, accurate, and complete in accordance with IDAPA 58.01.01.123 124.

Responsible Official Signature

Regional Director, Pipeline Operations
Responsible Official Title

5/26/2020
Date

Rick Duncan
Print or Type Responsible Official Name

Instructions for Form GI

Facility Information:

1. Provide facility name. If the facility is doing business as (dba) a facility different in name than the primary facility, provide the dba name.
2. If the facility is an existing permitted facility in Idaho, provide the facility identification number. If the facility is new and does not yet have a Facility ID, leave blank.
3. Provide a brief project description.
4-7. Provide the name of the *primary* contact person for this permit application. Provide title, telephone number, and e-mail address for the primary contact person.
8. Provide mailing address where DEQ should mail the final permit.
9. Provide the physical address where the equipment or facility is located (if different than 8).
10. Provide the Idaho County where the equipment or facility is located.
11. Indicate if equipment is portable by checking the appropriate box.
12. Provide the primary and secondary (if applicable) North American Industry Classification System (NAICS) code(s) for your facility.
13. Describe the primary activity and principal product of your business as it relates to the NAICS code listed in 12.
14. Identify and describe any other sources or equipment owned and operated by the primary facility that are located on contiguous or adjacent properties and the role the source or equipment plays in supporting the primary facility.

Permit Application Type:

15. Check the box describing the type of permit application. Provide the permit number as applicable.

    Important note: Applications can be mailed hard copy or submitted electronically (PDF version) to:

    Idaho Department of Environmental Quality
    Attn: Air Quality Program
    1410 North Hilton
    Boise, ID 83706-1255

    Electronically: Send to the Stationary Source Permit Program Coordinator (see the DEQ website)

PTC Fee:

Important note: If application is for a permit to construct (PTC), include the application fee of $1,000 when submitting the application. Per IDAPA 58.01.01.226.02, DEQ cannot process the application without the fee, which must be submitted with the application.

If paying PTC Fee with a check, make the check payable to the Idaho Department of Environmental Quality, and send with the application to the above address:

If paying with a credit card or E-check, payment can be made at https://www.accessidaho.org/ai/payport/online/deq/index.html (***Note:*** *Convenience fee of 3% applies to credit card payments, $5 to E-check payments.*)

If paying by bank wire transfer the DEQ Fiscal Office at (208) 373-0446.

16. For existing Tier I facilities that are applying for a PTC, the applicant must specify how the PTC will be incorporated into the Tier I permit (IDAPA 58.01.01.209.05). If you have questions, call the Air Permit Hotline at 1-877- 5Permit (1-877-573-7648).
17. Check this box to indicate if you want to review a draft permit before the final permit is issued.
18. Check this box to indicate if you want to request a permit hand-off meeting. This meeting is an opportunity to meet with DEQ staff to further understand how to demonstrate and maintain compliance with your permit conditions. If this box is checked, a DEQ representative will contact you to schedule a permit hand-off meeting after the final permit has been issued.

Certification of Truth, Accuracy, and Completeness (by Responsible Official):

Provide the name, title, address, telephone number, and e-mail of the facility's responsible official. Responsible Official is defined in IDAPA 58.01.01.006. The responsible official must sign and date the application before it is submitted to DEQ. **Important note:** DEQ does accept applications submitted via e-mail (PDF version) as long as it has a representation of the actual signature of the responsible official.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Gas Transmission Northwest, LLC	Compressor Station 5	055-0033
4. Brief Project Description:	See application text	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	UNIT 5D
6.	EU ID Number:	UNIT 5D
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	SOLAR
9.	Model:	TITAN 130
10..	Maximum Capacity:	21,087 HP
11.	Date of Construction:	March 2021
12.	Date of Modification (if any):	
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	NA		
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	8,760 HOURS/YR
23.	Maximum Operation:	8,760 HOURS/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

Instructions for Form EU0

This form provides DEQ with information about an emissions unit. An emissions unit is the equipment or process that generates emissions of regulated air pollutant(s). This form is used by the permit writer to become familiar with the emissions unit (EU). This form is also used by DEQ to identify the control equipment and the emission point (stack or vent) used for the emission unit(s) proposed in this permit application. This form also asks for supporting documents to verify stated control efficiencies and details about the emission point. Additional information may be requested.

1 - 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

5. Provide the name of the emissions unit (EU), such as “Union boiler,” etc. A separate EU0 form is required for each emissions unit.

6. Provide the identification (ID) number of the EU. It can be any unique identifier you choose; however, this ID number should be unique to this EU and should be used consistently throughout this application and any other air quality permit application(s) (e.g., operating permit application) to identify this EU.

7. Indicate the type of EU by checking the appropriate box (e.g., a new source to be constructed, an unpermitted existing source (as-built) applying for the first time, or an existing permitted source to be modified). If the EU is being modified, indicate on the form the most recent permit issued for the EU.

8. Provide the manufacturer's name for the EU. If the EU is custom-designed or homemade, indicate so.

9. Provide the model number of the EU. If the EU is custom-designed or homemade, indicate so.

10. Provide the maximum capacity of the EU. For example, a boiler’s rated capacity may be modified in units of MMBtu/hr in terms of heat input of natural gas; an assembly line capacity may be in parts produced per day. Capacity should be based on a rated nameplate or as stated in the manufacturer’s literature.

11. The date of construction is the month, day, and year in which construction or modification was commenced.

Definitions:

Construction fabrication, erection, or installation of an affected facility.

Commenced an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Modification any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted to the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) to the atmosphere not previously emitted.

12. If the EU has been or will be modified, provide the month, day, and year of the most recent or future modification as defined in IDAPA 58.01.01.006.

13. Indicate if emissions from the EU are controlled by air pollution control equipment. If the answer is yes, complete the next section. If the answer is no, go to line 18.

14. Provide the name of the air pollution control equipment (e.g., wet scrubber) and the control equipment’s identification number. This identification number should be unique to this air pollution control equipment and should be used consistently throughout this and all other air quality permit applications (e.g., operating permit application) to identify this air pollution control equipment.

15. Provide the date the air pollution control equipment was installed.

16. If the air pollution control equipment has been modified, provide the date of the modification.

17. Provide the name of the manufacturer and the model number for the air pollution control equipment.

18. If this air pollution control equipment controls emissions from more than this EU, provide the identification number(s) of the other EU(s).

19. Indicate if this air pollution control equipment operates on a schedule different from the EU(s) it controls.

20. Indicate if the air pollution control manufacturer guarantees the control efficiency of the control equipment. If the answer is yes, attach the manufacturer's guarantee and label it with the air pollution control equipment identification number. Indicate the control efficiency for the target pollutant(s).

21. If the control efficiency of the air pollution control equipment is not guaranteed, attach the design specifications and any performance data to support the control efficiency stated in part 16. Label the supporting documentation with the air pollution control equipment identification number.

22. Provide the projected actual operating schedule for the emission unit in hours/day, hours/year, or other.

23. Provide the maximum operating schedule for the emission unit in hours/day, hours/year, or other.

24. If you are requesting to have limits placed on this EU, mark "Yes." Then, check the applicable requested limit(s) and provide the limit(s). For example, production limits may be in terms of parts produced per year, material usage limits may be in gallons per day.

25. Please provide the reason you are requesting limits, if any. This helps DEQ and the applicant determine whether the limits are necessary, and if they will accomplish the desired purpose. Provide supporting documentation (calculations, modeling assessment, regulatory review, etc.) for each limit requested.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units Industrial IC Engine Information - **Form EU1**
Revision 9
10/23/13

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name	2. Facility Name:
Gas Transmission Northwest, LLC	Compressor Station 5

3. Brief Project Description:	Replacement of existing combustion turbine Unit 5B and the existing emergency generator with a new Solar Titan 130 Turbine and a new emergency generator.

IC ENGINE DESCRIPTION AND SPECIFICATIONS

4. Type of unit:

☒ New unit ☐ Unpermitted existing unit ☐ Modification to an existing permitted unit? Permit number: _____
☐ Full-time operation (non-emergency standby use)?
☒ Emergency standby use only (operation limited to 100 hrs/yr for maintenance and testing and emergency use only)?
☐ Emergency fire pump use only?
☐ Stationary test cell/stand operation only (as defined in NSPS Subpart ZZZZ)?
☐ National security operation only (as defined in NSPS Subpart ZZZZ)?
☐ Institutional emergency standby IC engine (as defined in NSPS Subpart ZZZZ)?

IC ENGINE SPECIFICATIONS

Questions 5 through 15 apply to **all IC engines**.

5. IC Engine Manufacturer: Caterpillar 6. Model: G3512 7. Date manufactured: 2020 8. Model year: 2020

9. Date of installation (if an existing IC engine): 2021 10. IC Engine cylinder displacement: 52 liters per cylinder

11. Maximum rated horsepower (per the data plate/manufacturer specifications): 1827 bhp

12. EPA Certification: Tier certification number _____ or ☒ None/not tier certified

13. Ignition type: ☒ Spark ☐ Compression

14. Fuel combusted in the IC engine? ☐ Distillate fuel oil ☒ Natural gas/LNG ☐ LPG/propane
If distillate fuel oil (#1, #2, or a mixture) is used, what is the maximum sulfur content? ☐ 15 ppm (0.0015% by weight) ☐ 500 ppm (0.05% by weight)

15. IC engine exhaust stack parameters: Diameter TBD inches Height TBD feet Temperature 955 °F Flow rate 10319 acfm

IC ENGINE EMISSIONS PARAMETERS

Questions 16 through 27 apply to **full-time** non-Tier certified IC engines or Tier certified IC engines manufactured prior to July 11, 2005. If you are proposing a Tier certified IC engine manufactured on and after July 11, 2005 or an emergency standby IC engine do not answer questions 17 through 27.

16. Testing schedule (for emergency standby IC engines only): 1 hrs/day 4 hrs/mon 16 hrs/qtr 52 hrs/yr

17. Maximum daily operation: _____ hrs/day 18. Maximum annual operation: _____ hrs/yr **Note:** These operational limits will be placed in the permit.

19. Will CO emissions be limited to a specific ppmvd (i.e. 49 or 23 ppmvd)? ☐ Yes ☐ No 20. What will the CO emissions limit be? _____ ppmvd

21. Will CO emissions be reduced by 70% or more? ☐ Yes ☐ No

22. Will a CEMS (Continuous Emissions Monitoring System) be used to measure pollutants in the IC engine exhaust stream? ☐ Yes ☐ No

23. Will a CPMS (Continuous Parameters Monitoring System) be used to measure parameters of the IC engine exhaust stream? ☐ Yes ☐ No

24. Will the IC engine be equipped with an oxidation catalyst? ☐ Yes ☐ No

25. If applicable, will the oxidation catalyst be equipped with a temperature measurement system to ensure it is operating properly? ☐ Yes ☐ No

26. Will the IC engine be equipped with a diesel particulate filter? ☐ Yes ☐ No

27. If applicable, will the diesel particulate filter be equipped with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached? ☐ Yes ☐ No

Instructions for Form EU1

Please refer to IDAPA 58.01.01.220 for a list of the general exemption criteria for Permit to Construct exemptions.

1 – 3. Provide the same company name, facility name (if different), and brief project description as on Form GI. This is useful if the application pages are separated.

USE ATTACHMENT IF ADDITIONAL SPACE IS REQUIRED.

General Information:

4. Indicate whether the IC engine is a new unit, unpermitted existing unit, being modified, and whether it will be permitted to operate full-time or for emergency use only.

IC Engine Specifications:

5-8. Provide the IC engine manufacturer, model, date the IC engine was manufactured, and the model year (used for EPA certification purposes) of the IC engine.

9. Provide the date of installation of the IC engine.

10. Provide the IC engine cylinder displacement (i.e. 12 liter engine with 8 cylinders = 1.5 liters per cylinder).

11. Provide the maximum horsepower of the IC engine (per the data plate) in bhp.

12. Provide the EPA Tier certification number of the IC engine (i.e. 1, 2, 3, or 4).

13. Provide the IC engine ignition type.

14. Check which fuel is combusted in the IC engine. If distillate fuel oil is combusted, check the maximum proposed sulfur content of the fuel.

15. Provide the IC engine exhaust stack parameters. The temperature and flow rate should be per the IC engine manufacturer. If the stack height is very tall, provide a justification for the exhaust gas temperature.

IC Engine Emissions Parameters:

Questions 16 through 27 apply to **full-time** non-Tier certified IC engines or Tier certified IC engines manufactured prior to July 11, 2005. If you are proposing a Tier certified IC engine manufactured on and after July 11, 2005 or an emergency standby IC engine do not answer questions 17 through 27.

16. For emergency IC engines only, propose a testing schedule.

17. Propose a maximum daily IC engine hourly limit. **Note:** Unless it is 24 hours per day of operation, this proposed daily hourly limit will be placed in the permit.

18. Propose a maximum annual IC engine hourly limit. **Note:** Unless it is 8,760 hours per year of operation, this proposed annual hourly limit will be placed in the permit.

19-21. Subpart ZZZZ requires that CO emissions in the exhaust from existing non-Tier certified IC engines are either limited to a specific concentration, 49 ppmvd for engines rated at 300 bhp to ≤ 500 bhp or 23 ppmvd for engines rated at > 500 bhp, or are to reduce the CO concentration by 70% or more. Therefore, “yes” should only be answered to one of these two questions.

22-23. Subpart ZZZZ requires that, for IC engines rated at > 500 bhp, Applicants either install a CEMS (Continuous Emissions Monitoring System) or a CPMS (Continuous Parameters Monitoring System) in the exhaust stream to demonstrate compliance with the emissions limitations. Therefore, “yes” should only be answered to one of these two questions.

24. Specify if the IC engine is equipped, or will need to be equipped, with an oxidation catalyst to comply with the emissions limitations of Subpart ZZZZ.

25. Specify if the oxidation catalyst will be equipped with a temperature measurement system to ensure that is operating properly to comply with the emissions limitations of Subpart ZZZZ.

26. Specify if the IC engine is equipped, or will need to be equipped, with a diesel particulate filter to comply with the emissions limitations of Subpart ZZZZ.

27. Specify if the diesel particulate filter will be equipped with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Federal Rule Applicability **– Form FRA**
6/7/2018

In each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name:	2. Facility Name:
Gas Transmission Northwest, LLC	Compressor Station 5
3. Brief Project Description:	GTN is proposing to replace the existing combustion turbine Unit 5B and the existing emergency generator with a new Solar Titan 130 turbine (Unit 5D) and a new emergency generator (Unit AUX-1).

APPLICABILITY DETERMINATION	
4. List all applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). List all non-applicable subparts of the NSPS which may appear to apply to the facility but do not. Examples of NSPS-affected emissions units include internal combustion engines, boilers, turbines, etc. Applicant must thoroughly review the list of affected emissions units.	List of all applicable subpart(s): A, JJJJ, KKKK, OOOOa List of all non-applicable subpart(s) which may appear to apply but do not: Dc ☐ Not Applicable
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) (40 CFR part 61 and 40 CFR part 63). List all non-applicable subparts of the NESHAP which may appear to apply to the facility but do not. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. Reference EPA's webpage on NESHAPs for more information.	List of all applicable subpart(s): 40 CFR part 63, Subpart ZZZZ List of all non-applicable subpart(s) which may appear to apply but do not: 40 CFR part 63 Subpart YYYY; 40 CFR part 63 Subpart JJJJJJ ☐ Not Applicable
6. For each subpart identified above, conduct a complete regulatory analysis using the instructions and referencing the example on the following pages. **Note**: Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation does or does not apply. Regulatory reviews submitted with insufficient detail will be determined incomplete.	☒ A detailed regulatory review has been provided ☐ DEQ has already been provided a detailed regulatory review (please provide a reference)

IF YOU ARE UNSURE HOW TO ANSWER ANY OF THESE QUESTIONS, CALL THE AIR PERMIT HOTLINE AT 1-877-5PERMIT.

It is emphasized that it is the applicant's responsibility to satisfy all technical and regulatory requirements, and that DEQ will help the applicant understand those requirements prior to submittal of the application but that DEQ will not perform the required technical or regulatory analyses on the applicant's behalf.

Instructions for Form FRA

1 – 3. Provide the company name, facility name (if different), and a brief project description.

Applicability Determination

4 - 5. It is important that facilities review the most recent federal regulations when submitting their permit application to DEQ. Current federal regulations can be found at the following website: https://www.ecfr.gov.

6. For each applicable subpart identified under items 4-5, conduct a complete regulatory analysis. The facility must follow the procedure given below or obtain permission from DEQ to provide the necessary information using an alternative procedure:

   a. Retrieve a TEXT or PDF copy of the applicable federal regulation subpart(s) online at https://www.govinfo.gov or from https://www.ecfr.gov for the next step.

   b. Copy and paste the regulation(s) into the DEQ air permit application.

   c. Highlight or underline sections in the regulation(s) that are applicable to the source(s).

   d. Under each section of the subpart, explain why the source is or is not subject to the section in addition to how the source will comply with the section. When providing the explanation use a different font than the regulation (i.e. *italics*) so that it is easy for the reader to determine the text provided by the applicant. An example NSPS regulatory analysis follows. The applicant must provide all information needed to determine applicability. If information is lacking or the analysis is incomplete, the application will be determined incomplete.

   e. Information on NSPS/NESHAP applicability determinations that may be useful to applicants is available on EPA's website under Clean Air Act Applicability Determination Index. Another useful source of information is the preamble to the regulation which is published in the Federal Register on the date the regulation was promulgated. Federal Registers may be found online at https://www.federalregister.gov. The date the regulation was published in the Federal Register is included in the footnotes of the regulation.

      DEQ will assist in identifying the applicable requirements that the applicant must include in the application, but will not perform the required technical or regulatory analysis on the applicant's behalf. Applicants should contact the Air Quality Permit Hotline (1-877-573-7648) to discuss NSPS/NESHAP regulatory analysis requirements or to schedule a meeting.

   f. Facilities should also document a non-applicability determination on federal air regulations which may appear to apply to the facility but actually do not. A non-applicability determination will avoid future confusion and expedite the air permit application review. If you conduct an applicability determination and find that your activity is not NSPS or NESHAP affected facility, an analysis should be submitted using the methods described above.

   g. It is not sufficient to simply provide a copy of the NSPS or NESHAP. The applicant must address each section of the regulation as described above and as shown in the example that follows.

Example of a NSPS Regulatory Analysis

Because the facility has a compression ignition IC engine the following NSPS requirements apply to this facility:

- **40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.**

The applicable parts are highlighted in yellow.

40 CFR 60	Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
§ 60.4200	Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

The ACME Plant operates two CI engines that were manufactured and commenced operation in 2007 and has proposed five new CI engines that are manufactured after April 1, 2006 and will commence operation in 2017. Therefore this section is applicable.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

The ACME Plant is an area source of criteria pollutants and HAPs and therefore is exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

The ACME Plant is not a stationary CI internal combustion engine manufacturer. Therefore, this section does not apply.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and 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 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

The engines operated by the ACME Plant have a maximum engine power of 450 bhp that have a displacement of less than 10 liters per cylinder and are not fire pump engines and are therefore required to meet the certification emission standards in 40 CFR 89.112 and 89.113.

And so forth……

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Version 1, August 2010

Facility Wide Hazardous Air Pollutant Potential to Emit
Application Template and Instructions

Provide the facility wide potential to emit for all Hazardous Air Pollutants (HAPs). **The potential to emit provided here must match the emissions rates which are requested to be permitted.**

HAPs are pollutants that are required to be regulated under the Clean Air Act. A list of the HAPs may be found by following this link: HAP list; review the list carefully to be sure you have included all listed HAPs.

All emissions inventories must be submitted with thorough documentation. The emission inventories will be subjected to technical review; prepare your application with sufficient documentation so that either the public or DEQ can verify the validity of the emission estimates. **Applications submitted without sufficient documentation are incomplete. Follow the instructions provided on the following page; do not proceed until you have read the instructions.**

Applicants must use the Potential to Emit Summary table provided below. Identify the individual HAP with the highest emissions and total HAP emissions. The potential to emit provided here must match the emissions rates which are requested to be permitted. **All fugitive emissions of HAPs must be included.**

Total Facility HAP POTENTIAL TO EMIT EMISSIONS SUMMARY

HAP Pollutants	PTE (T/yr)
CH_2O*	**1.74**
Total	**2.48**

* Maximum Individual HAP
**See Emission calculations for further details

Applicants are encouraged to call DEQ's Air Quality Permit Hotline (1-877-573-7648) to ask questions as they prepare the application.

Emission Inventory Instructions:

1. Use the same emission unit name throughout the application (i.e. in air pollution control equipment forms and for modeling purposes).

2. The application must **show in detail all calculations** used to develop the PTE summary and include:

   - Electronic copies of any spreadsheets used to estimate emissions. If a spreadsheet is used submit an electronic copy of the spread sheet (i.e. Excel File).
   - Documentation of all calculations conducted by hand (i.e. show all calculations).
   - Clear statements on all assumptions relied upon in estimating emissions.
   - Documentation of the emissions factors used to estimate emissions. If the emissions factor documentation is readily available to DEQ, such as an EPA AP-42 emissions factor, a simple reference to the emissions factor suffices. If the emissions factor documentation is not readily available to DEQ the applicant must submit the documentation with the application; ask DEQ if you are uncertain. **Applications without sufficient documentation are incomplete.** Documentation may consist of manufacturer guarantees, research conducted by trade organizations, published emission factors, and source test results. **If there are multiple factors for a given operation, note why the factor used is the most representative.**
   - Copies of manufacturer guarantees upon which emission inventories are based.
   - The best available emission information (see DEQ's Guidance on Emissions Data Hierarchy).
   - If source tests are used as the basis for emissions estimates the source test report must be submitted. If the source test report is on file with DEQ provide the date of the source test was submitted along with the name of the facility and the emission unit that was tested. Source data from similar emissions units may be considered reliable provided it is clearly described why the sources are similar. Similar sources are those that the applicant has shown serve a similar function, use similar raw materials, and have similar processing rates.

2. **All fugitive emissions of HAPs must be included[1].**

[1] November 27, 2001 (66 FR 59161), EPA published a rule, "Change to Definition of Major Source," that requires the fugitive emissions of all hazardous air pollutants ("HAPs") listed under section 112(b) of the Act in determining whether the source is a major source.

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Version 1, August 2010

Facility Wide Potential to Emit Emission Inventory

Application Template and Instructions

For new stationary sources provide the facility's potential to emit for all NSR Regulated Air Pollutants. The potential to emit provided here must match the emissions rates which are requested to be permitted.

For modifications to existing facilities (including the addition of new emissions units), if the existing facility classification is in question an existing facility wide potential to emit emission inventory will be required to be submitted[1]. Contact DEQ to determine if a facility wide emission inventory for the existing facility is required.

All emissions inventories must be submitted with thorough documentation. The emission inventories will be subjected to technical review. Therefore, prepare your application with sufficient documentation so that the public and DEQ can verify the validity of the emission estimates. **Applications submitted without sufficient documentation are incomplete. Follow the instructions provided on page 2; do not proceed until you have read the instructions.**

Applicants must use the Potential to Emit Summary table provided below.

Table 1. POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS

Emissions Unit	NOx[a]	CO[a]	CO2e[a]	PM/PM10/PM2.5[a]	VOC[a]	SO2[a]
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
5C	197.03	142.79	156,885	3.01	3.07	3.81
5D	41.29	128.97	87,081	4.91	6.50	0.53
AUX-1	2.01	4.03	382	0.03	1.01	0.001
Venting	0.00	0.00	1,339	0.00	0.49	0.00
Fugitive Sources *{For listed source categories only, see item 3 below in the instructions}*						
Equipment Leaks	0.00	0.00	17,948	0.00	6.52	0.00
Totals	**240.33**	**275.79**	**245,687**	**7.95**	**11.07**	**4.34**

a) NSR Regulated air Pollutants are defined[2] as: Particulate Matter (PM, PM-10, PM-2.5), Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone (VOC), Sulfur Dioxide, CO_2e[3], Green House Gases (GHG) mass, all pollutants regulated by NSPS (40 CFR 60)(i.e. TRS, fluoride, sulfuric acid mist) & Class I & Class II Ozone Depleting Substances (40 CFR 82)(i.e. CFC, HCFC, Halon, etc.)

---

[1] The applicant must determine if the existing facility is a major facility. If the facility is an existing PSD major facility and changes are being made to the facility the major modification test must be conducted.

[2] 40 CFR 52.21(b)(50), as incorporated by reference at IDAPA 58.01.01.107.03.d

[3] Multiply each green house gas (GHG) by the global warming potential (GWP) listed at 40 CFR 98, Table A- 1 of Subpart A then sum all values to determine CO_2e (GHGs are carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride). Be sure to show all calculations as described in the instructions.

Applicants are encouraged to call DEQ's Air Quality Permit Hotline (1-877-573-7648) to ask questions as they prepare the application.**Emission Inventory Instructions:**

1. Use the same emission unit name throughout the application (i.e. in air pollution control equipment forms and for modeling purposes).

2. The application must **show in detail all calculations** used to develop the PTE summary and include:

   - Electronic copies of any spreadsheets used to estimate emissions. If a spreadsheet is used submit an electronic copy of the spread sheet (i.e. Excel File).
   - Documentation of all calculations conducted by hand (i.e. show all calculations).
   - Clear statements on all assumptions relied upon in estimating emissions.
   - Documentation of the emissions factors used to estimate emissions. If the emissions factor documentation is readily available to DEQ, such as an EPA AP-42 emissions factor, a simple reference to the emissions factor suffices. If the emissions factor documentation is not readily available to DEQ the applicant must submit the documentation with the application; ask DEQ if you are uncertain. **Applications without sufficient documentation are incomplete.** Documentation may consist of manufacturer guarantees, research conducted by trade organizations, published emission factors, and source test results. **If there are multiple factors for a given operation, note why the factor used is the most representative.**
   - Copies of manufacturer guarantees upon which emission inventories are based.
   - The best available emission information (see DEQ's Guidance on Emission Data Hierarchy).
   - If source tests are used as the basis for emissions estimates the source test report must be submitted. If the source test report is on file with DEQ provide the date of the source test was submitted along with the name of the facility and the emission unit that was tested. Source data from similar emissions units may be considered reliable provided it is clearly described why the sources are similar. Similar sources are those that the applicant has shown serve a similar function, use similar raw materials, and have similar processing rates.

3. Fugitive emissions of NSR regulated air pollutants from the source categories listed below must be included in the emission inventory.

Listed Source Categories for Inclusion of Fugitive Emissions

- Coal cleaning plants (with thermal dryers)
- Kraft pulp mills
- Portland cement plants
- Primary zinc smelters
- Iron and steel mills
- Primary aluminum ore reduction plants
- Primary copper smelters
- Municipal incinerators -250 T/day of refuse
- Hydrofluoric, sulfuric, or nitric acid plants
- Petroleum refineries
- Lime plants
- Phosphate rock processing plants
- Coke oven batteries
- Sulfur recovery plants
- Carbon black plants (furnace process)
- Primary lead smelters
- Fuel conversion plants
- Sintering plants
- Secondary metal production plants
- Chemical process plants (excluding ethanol plants by natural fermentation).
- Fossil-fuel fired boilers totaling more than 250 MMBtu/hr
- Petroleum storage and transfer units with total capacity of 300,000 barrels
- Taconite ore processing plants
- Glass fiber processing plants
- Charcoal production plants
- Fossil fuel-fired steam electric plants greater than 250 MMBtu/hr)
- Categories regulated by NSPS or NESHAP prior to 8/7/80

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Version 2, October 2018

Proposed Minor Modification to an Existing Major Facility - Major Modification Test

Emission Inventory Application Template and Instructions

The requirements of PSD apply if a major modification is determined to occur to an existing PSD major facility using the procedures summarized in this document. The summaries provided are:

- Intended to be useful but are simplified versions of a complex regulation.
- Intended to be used in conjunction with reading the regulations (if there is conflict between the summaries provided here and the regulation, the regulation shall govern).
- Intended to facilitate discussions with DEQ during a pre-application meeting that the applicant has scheduled with DEQ.

Applicants are encouraged to read the regulation at 40 CFR 52.21(a)(2) and to schedule a meeting with DEQ to discuss application requirements. Applicants should contact DEQ's Air Quality Permit Hotline (1-877-573-7648) to schedule a meeting.

A project is a major modification for a regulated NSR pollutant if it causes two types of emissions increase: a significant emissions increase; and a significant net emissions increase.

Criteria for Triggering a Major Modification

√ Significant Emission Increase (1st Step)

and

√ Significant Net Emission Increase (2nd Step)

All emissions inventories must be submitted with thorough documentation. The emission inventories will be subjected to technical review. Therefore, prepare your application with sufficient documentation so that the public and DEQ can verify the validity of the emission estimates. **Applications submitted without sufficient documentation are incomplete.** Follow the instructions on the last page of this document; **do not proceed until you have read the instructions on all forms.**

Step #1 - Significant Emission Increase Determination

The procedure for calculating whether a significant emissions increase (*i.e.* the first step of the process) will occur depends upon the type of emissions units involved with the ***project*** (i.e. new, existing, or combination of new and existing). Procedures for conducting the 1st step test for sources that are not electric utility steam generating units are summarized below. Emissions reductions that are part of the project may be credited in determining if the project causes a significant emissions increase in Step #1.[1]

Project means a physical change in, or change in the method of operation of, an existing major stationary source (40 CFR 52.21(b)). **Sources not being physically modified but which could experience emissions increases that result from the change[2, 3] are required to be included in the project. The application must clearly describe which emission units are involved with the project.**

Projects Involving Only Existing Emission Units

*For **projects** that only involve existing emission units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the difference between the ***projected actual emissions*** and the ***baseline actual emissions*** for each existing emissions unit, equals or exceeds the significant amount for that pollutant as defined in paragraph 40 CFR 52.21(b)(23)).

Baseline Actual Emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by DEQ, whichever is earlier (40 CFR 52.21(b)(48)(iii)). The average rate **shall include all fugitive emissions to the extent quantifiable**, and emissions associated with startups, shutdowns, and malfunctions. The emissions shall be adjusted downward for any emissions that are not in compliance with an applicable requirement.

Projected Actual Emissions means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. The analysis **shall include all fugitive emissions to the extent quantifiable** and emissions associated

[1] E. Scott Pruitt EPA, Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program, March 13, 2018

[2] David Neleigh, Chief, Air Permits Section EPA Region 6. Letter to Dawson Lasseter, Air Quality Division, Oklahoma DEQ, January 27, 2005.

[3] R. Douglas Neeley, Chief, Air & Radiation Technology Section, Letter to Rs. Rhonda Banks Thompson, South Carolina Department of Health and Environmental Control, March 14, 1997 ("… when a particular physical change or change in the method of operation would cause an increase in emissions from other emissions units, then those "other" emissions must be included in determining PSD applicability for the particular change.")

with startups, shutdowns, and malfunctions. Projected actual emissions shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated *during the consecutive 24-month period used to establish the baseline* actual emissions and that are also unrelated to the particular project, including any increased utilization due to product demand growth[4]. In lieu of using the projected actual emissions a facility may elect to use the emissions unit's potential to emit.

Projects Only Involving New Emission Units

*For **projects** that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant occurs if the ***potential to emit*** of the new emission unit equals or exceeds the significant amount for that pollutant (i.e. baseline emissions are zero[5] for new units).

> New units that qualify as a "***replacement unit***" are treated as existing emission[6] units for major modification applicability purposes. For new units that qualify as replacement units, instead of using zero for baseline actual emissions, emissions from the unit that is being replaced are used to determine baseline actual emissions.
>
> ***Replacement unit***[7] means an emissions unit for which <u>all</u> the following criteria are met:
>
> - The emissions unit is a reconstructed unit within the meaning of NSPS, or the emissions unit completely takes the place of an existing emissions unit.
> - The emissions unit is identical to or functionally equivalent to the replaced emissions unit.
> - The replacement does not alter the basic design parameters (i.e. maximum rate of fuel or heat input, maximum rate of material input, maximum rate of product output, or other parameter approved by DEQ)
> - The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

Projects Involving Both Existing and New Emission Units

Hybrid test for projects that involve both new and existing emissions units - A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the methods described above for existing emissions unit and the procedures described above for new emissions units, equals or exceeds the significant amount for that pollutant.

[4] 40 CFR 52.21(b)(41)(ii)(c)
[5] 40 CFR 52.21(b)(48)(iii)
[6] 40 CFR 52.21(b)(7)
[7] 40 CFR 52.21(b)(33)

Following are emission inventory template tables that must be completed and submitted with the application to summarize the 1st step test of the major modification applicability determination.

Table 1 PTE FOR PROJECTED ACTUAL EMISSIONS

Emissions Unit	NOx T/yr	CO T/yr	PM/PM10/PM2.5 T/yr	VOC T/yr	SO2 T/yr
Point Sources					
5D (Turbine)	**41.29**	**128.97**	**4.91**	**6.50**	**0.53**
IA – Fuel Gas Heater	**0.43**	**0.36**	**0.03**	**0.02**	**0.003**
IA – Space Heaters	**0.12**	**0.10**	**0.01**	**0.01**	**0.001**
AUX-1 (Emergency Generator)	**2.01**	**4.03**	**0.03**	**1.01**	**0.002**
{Note: all quantifiable fugitive emissions, regardless of source category, are required to be included} **Fugitive Sources**					
Equipment Leaks				**6.52**	
Venting				**0.49**	
Facility Totals					
Total, Projected Actual Emissions	**43.85**	**133.45**	**4.98**	**8.03**	**0.54**

Table 2 BASELINE ACTUAL EMISSIONS

Emissions Unit	NOx T/yr	CO T/yr	PM/PM10/PM2.5 T/yr	VOC T/yr	SO2 T/yr
Point Sources					
5B	**62.64**	**111.85**	**0.40**	**0.28**	**0.40**
Existing Emergency Generator (691 hp)	**0.14**	**0.02**	**3.38E-04**	**3.99E-03**	**1.99E-05**
{Note: all quantifiable fugitive emissions, regardless of source category, are required to be included } **Fugitive Sources**					
Facility Totals					
Total, Baseline Actual Emissions	**62.78**	**111.87**	**0.40**	**0.28**	**0.40**

Table 3 COMPARISON OF THE PROJECT EMISSIONS INCREASE TO THE SIGNIFICANT EMISSIONS RATE THRESHOLDS

Emissions	NOx	CO	PM/PM10/PM2.5	VOC	SO2
	T/yr	T/yr	T/yr	T/yr	T/yr
Project Emissions Increase	**-18.92**	**21.59**	**4.59**	**7.75**	**0.14**
PSD Significance Emission Rate (SER) *See 40 CFR 52.21(b)(23)*	**40**	**100**	**15/10**	**40**	**40**
Does the Project Emissions Increase Exceed the Significant Emission Rate Threshold?	**No**	**No**	**No**	**No**	**No**

NSR Regulated air Pollutants are defined[8] as:

Particulate Matter (PM, PM-10, PM-2.5)
Carbon Monoxide
Lead
Nitrogen Dioxide
Ozone (VOC)
Sulfur Dioxide
All pollutants regulated by NSPS (40 CFR 60)(i.e. TRS, fluoride, sulfuric acid mist)
Class I & Class II Ozone Depleting Substances (40 CFR 82)(i.e. CFC, HCFC, Halon, etc.)
CO2e[9]
Green House Gases Mass (GHG - carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride)

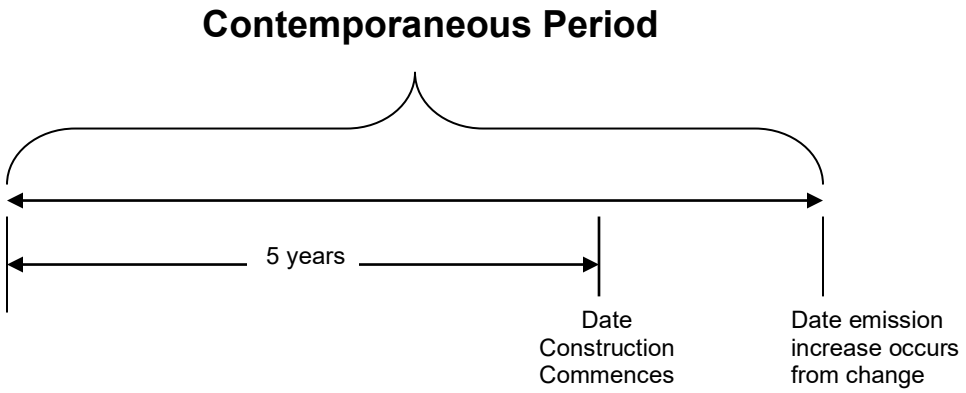
Step #2 - Significant Net Emission Increase Determination

Projects that cause a significant emission increase may opt to avoid triggering a major modification if it can be demonstrated that the project, and all other **creditable**, **contemporaneous** emissions increases and decreases, when combined, do not cause a significant net emission increase.

[8] 40 CFR 52.21(b)(50)), as incorporated by reference at IDAPA 58.01.01.107.03.d

[9] Multiply each green house gas (GHG) by the global warming potential (GWP) listed at 40 CFR 98, Table A- 1 of Subpart A then sum all values to determine CO_2e (GHGs are carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride). Be sure to show all calculations as described in the instructions.

The **contemporaneous**[10] period is illustrated below.



An increase or decrease in actual emissions is **creditable** only if:

A reviewing authority has not relied on it in issuing a permit and the permit is in effect when the increase in actual emissions from the particular change occurs; and

An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level; and

An increase or decrease of SO_2, PM-10, or NO_x that occurs before the applicable minor source baseline date[11] is creditable only if it is required to be considered in calculating the PSD increment available[12]; and

A decrease in actual emissions is creditable only to the extent that:

- The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions.
- It is enforceable as a practical matter at and after the time that actual construction on the particular change begins.
- It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant.

Summary of the Netting Procedure

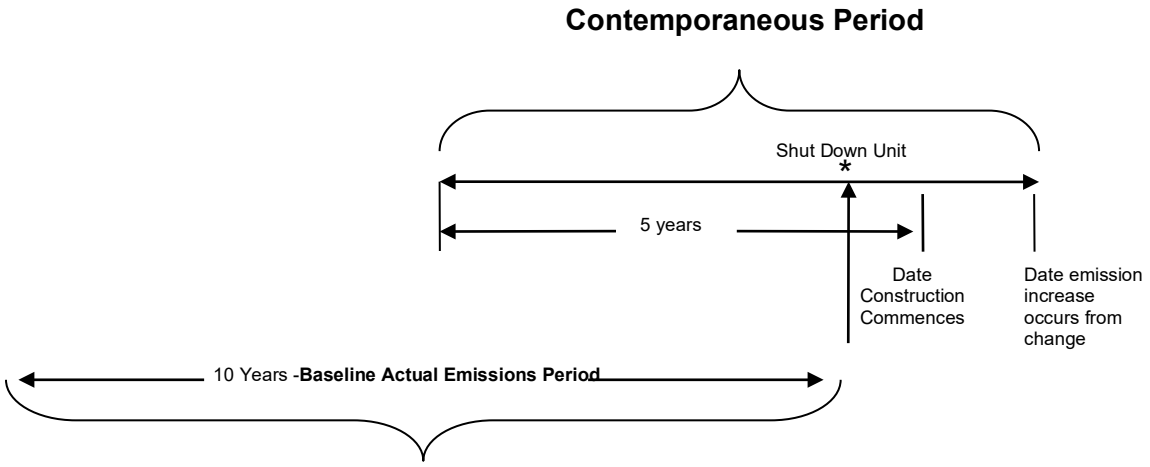
[10] 40 CFR 52.21(b)(3)(ii)
[11] The minor source baseline was triggered over 5 years ago for all pollutants in all Air Quality Regions with the exception that the minor source baseline date has not been triggered for SO_2 Air Quality Region 63.
[12] EPA guidance on calculating increment consumption must be reviewed to determine if emission decreases or increases prior to the minor source baseline date are required to be considered in determining the amount of increment available.

The definition of baseline actual emissions[13] must be used[14] to determine emission increase and decreases.

Some of the issues that arise when using the baseline actual emissions definition for determining emission increases and decreases in the netting procedure are illustrated and discussed below. The summaries provided here are intended to be useful. Even though the summaries are useful it still necessary to read the regulations and schedule a meeting with DEQ to discuss application requirements.

Shut Down Emission Unit

For an emission unit that is shut down during the contemporaneous period baseline actual emissions are used to determine the emissions reduction. Applicants may use the average annual emissions that occurred during any consecutive 24 month period that occurred during the 10 years preceding the change that occurred during the contemporaneous period[15] provided the emissions were compliant with any applicable requirement. This is illustrated in the following diagram.



Emission Unit Added During the Contemporaneous Period Which is Less Than 2 Years Old

For previously installed emission units that have not been in operation for more than two years[16] the potential to emit of that unit is used to determine the emission increase for netting purposes[17].

[13] 40 CFR 52.21(b)(48)
[14] 40 CFR 52.21(b)(3)(i)(b)
[15] FR 67, 80197, December 31, 2002
[16] Units that have not operated for more than two years are defined as new units (40 CFR 52.21(b)(7)(i)
[17] See 40 CFR 52.21(b)(3)(i)(b) and 40 CFR 52.21(b)(48)(iii)

Emission Inventory Instructions:

1. Use the same emission unit name throughout the application (i.e. in air pollution control equipment forms and for modeling purposes).
2. The application must **show in detail all calculations** used to develop the PTE summary and include:
    - Electronic copies of any spreadsheets used to estimate emissions. If a spreadsheet is used submit an electronic copy of the spread sheet (i.e. Excel File).
    - Documentation of all calculations conducted by hand (i.e. show all calculations).
    - Clear statements on all assumptions relied upon in estimating emissions.
    - Documentation of the emissions factors used to estimate emissions. If the emissions factor documentation is readily available to DEQ, such as an EPA AP-42 emissions factor, a simple reference to the emissions factor suffices. If the emissions factor documentation is not readily available to DEQ the applicant must submit the documentation with the application; ask DEQ if you are uncertain. **Applications without sufficient documentation are incomplete.** Documentation may consist of manufacturer guarantees, research conducted by trade organizations, published emission factors, and source test results. **If there are multiple factors for a given operation, note why the factor used is the most representative.**
    - Copies of manufacturer guarantees upon which emission inventories are based.
    - The best available emission information (see DEQ's Guidance on Emission Data Hierarchy on the website).
    - If source tests are used as the basis for emissions estimates the source test report must be submitted. If the source test report is on file with DEQ provide the date of the source test was submitted along with the name of the facility and the emission unit that was tested. Source data from similar emissions units may be considered reliable provided it is clearly described why the sources are similar. Similar sources are those that the applicant has shown serve a similar function, use similar raw materials, and have similar processing rates.
3. Fugitive emissions of all NSR regulated air pollutants, regardless of the source category, are required to be included in major modification determinations.

Appendix E

Air Dispersion Modeling Report

Air Dispersion Modeling Report

Gas Transmission Northwest LLC
Compressor Station 5
Athol, Idaho



Prepared for:

Gas Transmission Northwest, LLC

700 Louisiana Street
Houston, TX 77002

TC Energy

WENCK
Responsive partner.
Exceptional outcomes.

Prepared by:

WENCK Associates, Inc.
1800 Pioneer Creek Center
Maple Plain, MN 55359
Phone: 763-479-4200
Fax: 763-479-4242

Table of Contents

1.0 SUMMARY 1

2.0 PROJECT DESCRIPTION AND BACKGROUND AS IT RELATES TO MODELING ANALYSES 1

2.1 General Facility/Project Description 1
2.2 Location of Project 1
2.3 Existing Permits and Modeling Analyses Performed 2

3.0 MODELING ANALYSES APPLICABILITY AND PROTOCOL 2

3.1 Applicable Standards 2
3.2 Criteria Pollutant Modeling Applicability 3
3.3 TAP Modeling Applicability 4
3.4 Modeling Protocol 5

4.0 MODELED EMISSION SOURCES 5

4.1 Criteria Pollutants 5
4.1.1 Modeled Emissions Rates for Significant Impact Level Analyses 5
4.1.2 Modeled Emissions Rates for Cumulative Impact Analyses 5
4.1.3 NO_2/NOx Ratio for NOx Chemistry 5
4.1.4 Special Methods for Modeling Criterial Pollutant Emissions 6
4.2 Toxic Air Pollutants 6
4.3 Emission Release Parameters 6

5.0 MODELING METHODOLOGY 6

5.1 Model Selection 7
5.2 Meteorological Data 7
5.3 Effects of Terrain 8
5.4 Facility Layout 8
5.5 Effects of Building Downwash 8
5.6 Ambient Air Boundary 8
5.7 Receptor Network 8
5.8 Background Concentrations 9
5.9 NO_x Chemistry 10

6.0 RESULTS AND DISCUSSION 10

6.1 Criteria Pollutant Impact Results 10
6.1.1 Significant Impact Level Analyses 10
6.1.2 Cumulative NAAQS Impact Analyses 10
6.2 TAP Impact Analyses 11

7.0 QUALITY ASSURANCE/CONTROL 11

TABLES

Table 3.1-1 Applicable Regulatory Limits.....2
Table 3.2-1 Modeling Applicability.....3
Table 3.3-1 TAP ELS AND AACS/AACCS.....4
Table 5-1 Modeling Parameters.....6
Table 5.5-1 Building Dimensions.....8
Table 5.8-1 Background Monitors.....9
Table 6.1-2-1 GTN Station 5 Results for Cumulative NAAQS Impact Analysis 11
Table 6.2-1 GTN Station 5 Results for TAP Impacts Analyses.....11

APPENDICES

A Figures
B Stack Discharge Parameter Rates and Emissions

1.0 Summary

This memorandum summarizes the air dispersion modeling analysis completed for Gas Transmissions Northwest LLC's (GTN) – Compressor Station 5 located in Athol, ID. As part of the Permit to Construct Application (PTC) and Tier I Operating Permit Significant Modification Application, the Idaho Department of Environmental Quality (DEQ) requested a modeling analysis of the applicable pollutants to demonstrate compliance with the National Ambient Air Quality Standard (NAAQS) and toxic air pollutants (TAP). A Significant Impact Level (SIL) analysis was forgone based on agency direction. The NAAQS analysis was completed to evaluate carbon monoxide (CO), sulfur dioxide (SO_2), particulate (PM_{10} and $PM_{2.5}$), and nitrogen oxides (NO_x) from the facility. TAPs were also evaluated as part of the analysis. The following document outlines the conventions and assumptions that were used to complete the requested modeling analysis.

2.0 Project Description and Background as it Relates to Modeling Analyses

2.1 General Facility/Project Description

TC Energy owns and operates the Gas Transmission Northwest LLC (GTN) – Compressor Station 5 located in Athol, ID. Compressor Station 5 transports natural gas along the pipeline by receiving low-pressure inlet natural gas and compressing the stream to increase the pressure and maintain the downstream flow.

GTN is proposing to modify Compressor Station 5 by replacing the existing turbine, Unit 5B along with associated piping and ancillary equipment with a new turbine, Unit 5D (Solar Titan 130 – 21,087 hp). GTN is also proposing to replace the existing emergency generator with a new emergency generator, Unit AUX-1 (1,827 hp). GTN is also proposing to install one fuel gas heater, six space heaters, and fugitive equipment leaks and blowdowns for the proposed turbine. Compressor Station 5 also consists of one existing turbine, Unit 5C. The station also operates an existing heater, existing pipeline fluids tank and fugitive equipment leaks and blowdowns. As mentioned above, the proposed turbine will replace existing Unit 5B. All other existing equipment will remain at Compressor Station 5.

Figure 1 describing the source location and modeled equipment is included in Appendix A. The modeling analysis includes the existing turbine 5C, proposed turbine 5D, and the fuel gas heater. The proposed emergency generator was not modeled as it is an intermittent source and an exempt source under Idaho Air Rule Section 220-223.

2.2 Location of Project

GTN Compressor Station 5 is located in Athol, ID. The coordinates of the station are UTM E: 518,317.00 meters, and UTM N: 5,307,073.00 meters in UTM zone 11. The station is in Kootenai County at 2244 E. Seasons Road in Athol, ID. Kootenai County is classified as "attainment" or "unclassifiable" for all National Ambient Air Quality Standards for all pollutants for which NAAQS have been promulgated.

According to the Kootenai County 2020 Comprehensive Plan Land Use Map, the area surrounding Compressor Station 5 is primarily characterized by the country category. Therefore, Compressor Station 5 is considered to be a rural source. Additionally, Compressor Station 5 is primarily located in an area of flat terrain.

2.3 Existing Permits and Modeling Analyses Performed

Compressor Station 5 currently operates under a Tier I Operating Permit (Permit No. T01-2016.0024). The permit was most recently issued on May 2, 2017 and will expire on May 2, 2022. TC Energy is unaware of any modeling analyses performed in support of previous permitting projects at the station.

3.0 Modeling Analyses Applicability and Protocol

3.1 Applicable Standards

Design concentrations will follow Idaho DEQ guidelines which will sum the facility impact with the associated background concentrations. Criteria pollutant NAAQS are listed in Table 3.1-1, along with SILs. As described above, GTN completed a NAAQS analysis only.

Table 3.1-1 Applicable Regulatory Limits

Pollutant	Averaging Period	Significant Impact Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms/cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for

each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.

k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

Please see additional information on TAPs modeling in Section 3.3.

3.2 Criteria Pollutant Modeling Applicability

Table 3.2-1 lists criteria pollutants for which site-specific modeling analyses were performed to demonstrate compliance with NAAQS.

Table 3.2-1 Modeling Applicability

Criteria Pollutant	Modeled (yes/no)	Basis for Exclusion from Modeling
$PM_{2.5}$ 24-hour	Yes	NA
$PM_{2.5}$ annual	Yes	NA
PM_{10} 24-hour	Yes	NA
NO_2 1-hour	Yes	NA
NO_2 annual	Yes	NA
SO_2 1-hour, 3-hour	Yes	NA
SO_2 annual	Yes	NA
CO 1-hour, 8-hour	Yes	NA

a. If the project would have qualified for a Category I BRC permitting exemption for the criteria pollutant in question, as per Idaho Air Rules Section 221.01, except for the emissions quantities of another criteria pollutant, then a NAAQS compliance analysis is not required under Section 203.02 or 403.02 for that criteria pollutant.
b. Level I Modeling Thresholds from Table 2 in Section 3 of the DEQ Modeling Guideline. NAAQS compliance is assured through DEQ's non-site-specific modeling analyses.
c. Level II Modeling Thresholds from Table 2 in Section 3 of the DEQ Modeling Guideline. NAAQS compliance is assured through DEQ's non-site-specific modeling analyses. Level II Modeling Thresholds can only be used with prior DEQ approval.

3.3 TAP Modeling Applicability

Table 3.3-1 below summaries the TAPs included in the modeling analysis. Any TAP that exceeds the screen emissions level was included in the dispersion modeling and compared to the applicable AAC or AACC.

Table 3.3-1 TAP ELS AND AACS/AACCS

TAP	Non-Carcinogen or Carcinogen	Screening Emissions Level (EL)[a] (lb/hr)	Source Emissions Rate (lb/hr)	AAC or AACC[b] (µg/m³)
3-Methylchloranthrene	Carcinogen	2.50E-06	1.76E-09	-
7,12-Dimethylbenz(a)anthracene	Non-Carcinogen	1.33E-01	1.57E-08	-
1,1,2,2-Tetrachloroethane	Carcinogen	1.10E-05	0.00E+00	-
1,1,2-Trichloroethane	Carcinogen	4.20E-04	0.00E+00	-
1,3-Butadiene	Carcinogen	2.40E-05	2.05E-04	3.60E-03
1,3-Dichloropropene	Carcinogen	1.90E-07	0.00E+00	-
2,2,4-Trimethylpentane	Non-Carcinogen	2.33E+01	0.00E+00	-
Acetaldehyde	Carcinogen	3.00E-03	1.90E-02	4.50E-01
Acrolein	Non-Carcinogen	1.70E-02	3.04E-03	-
Benzene	Carcinogen	8.00E-04	5.71E-03	1.20E-01
Benzo(a)pyrene	Carcinogen	2.00E-06	1.18E-09	-
Biphenyl	Non-Carcinogen	1.00E-01	0.00E+00	-
Carbon Tetrachloride	Carcinogen	4.40E-04	0.00E+00	-
Chlorobenzene	Non-Carcinogen	2.33E+01	0.00E+00	-
Chloroform	Carcinogen	2.80E-04	0.00E+00	-
Ethylbenzene	Non-Carcinogen	2.90E+01	1.52E-02	-
Ethylene Dibromide	Carcinogen	3.00E-05	0.00E+00	-
Formaldehyde	Carcinogen	5.10E-04	3.38E-01	7.70E-02
Hexane	Non-Carcinogen	1.20E+01	1.76E-03	-
Methanol	Non-Carcinogen	1.73E+01	0.00E+00	-
Naphthalene	Non-Carcinogen	3.33E+00	6.19E-04	-
PAH	Non-Carcinogen	9.10E-05	1.05E-03	1.40E-02
Phenol	Non-Carcinogen	1.27E+00	0.00E+00	-
Propylene Oxide	Non-Carcinogen	3.20E+00	1.38E-02	-
Styrene	Non-Carcinogen	6.67E+00	0.00E+00	-
Tetrachloroethane	Carcinogen	1.10E-05	0.00E+00	-
Toluene	Non-Carcinogen	2.50E+01	6.18E-02	-
Xylene	Non-Carcinogen	2.90E+01	3.04E-02	-
Arsenic	Carcinogen	1.50E-06	1.96E-07	-
Cadmium	Carcinogen	3.70E-06	1.08E-06	-
Chromium	Non-Carcinogen	3.30E-02	1.37E-06	-
Cobalt	Non-Carcinogen	3.30E-03	8.24E-08	-
Nickel	Carcinogen	2.70E-05	2.06E-06	-
Selenium	Non-Carcinogen	1.30E-02	2.35E-08	-

a. ELs from Idaho Air Rules Section 585 and 586 in pounds/hour.

b. Acceptable Ambient Concentration (AAC) or Acceptable Ambient Concentration for a Carcinogen (AACC) from Idaho Air Rules Section 585 and 586, in micrograms/cubic meter or milligrams/cubic meter. Note that AACs listed in Idaho Air Rules Section 585 are expressed in units of milligrams/cubic meter rather than micrograms/cubic meter. The AAC or AACC is only listed for pollutants that are above the EL and require modeling.

3.4 Modeling Protocol

A modeling protocol was not submitted to the Idaho DEQ prior to the modeling report.

4.0 Modeled Emission Sources

Well-defined exhaust stacks are represented as "point" sources in the modeling analysis. Point sources are defined in the model by the emission rate and discharge parameters for stack height, stack temperature, exhaust flowrate, exit velocity, and stack diameter. As described in Section 2.1, modeled point sources at the facility include turbines 5C, 5D, and the proposed fuel gas heater, FG1. Potential emissions calculated as part of the PTC and Tier I Operating Permit Significant Modification Application will be used for the modeled emission rates for all sources. There are no differences between the potential emissions presented for the permit application and those included in the modeling analysis.

The discharge parameters, emission rates, and justification for the point sources are outlined in Appendix B. The emergency generator, space heaters, and existing tanks are considered exempt sources under Idaho Air Rules Section 220-223 and are therefore excluded from this demonstration. In addition, the proposed emergency generator is an intermittent sources.

4.1 Criteria Pollutants

4.1.1 Modeled Emissions Rates for Significant Impact Level Analyses

As previously mentioned, a SIL analysis was forgone based on agency direction.

4.1.2 Modeled Emissions Rates for Cumulative Impact Analyses

Modeled emission rates for modeled sources are described in Section 4.0. Additionally, emission estimates are based on 8,760 operating hours per year.

The discharge parameters, emission rates, and justification for the point sources are outlined in Appendix B. The emission rates in Appendix B are the same as those in the modeled input files. As noted above, emission calculations are also included with the PTC and Tier I Operating Permit Significant Modification Application.

4.1.3 NO_2/NOx Ratio for NOx Chemistry

AERMOD's Ambient Ratio Method, version 2 (ARM2) was used to model NO_x emissions. ARM2 provides estimates of representative equilibrium ratios of NO_2 to NO_x concentrations based on measured ambient levels of NO_2 and NO_x derived from national data from the EPA's Air Quality System. Source-specific NO_2/NO_x in stack ratios (ISR) are unknown; therefore, ARM2 is an acceptable approach as opposed to the Tier III options. The ARM2 default maximum ISR value of 0.9 and the default minimum value of 0.5 was used.

4.1.4 Special Methods for Modeling Criterial Pollutant Emissions

There are no unique methods of handling criteria pollutant emissions for this modeling demonstration.

4.2 Toxic Air Pollutants

Modeling was performed for each TAP having total project emissions exceeding the TAP-specific Screening Emissions Level (EL). The modeled sources are turbines 5C, 5D and the proposed fuel gas heater, which is the same as the NAAQS analysis. The discharge parameters, emission rates, and justification for the point sources are outlined in Appendix B. The emission rates in Appendix B are the same as those in the modeled input files.

4.3 Emission Release Parameters

The discharge parameters (including release orientation), emission rates, and justification for the point sources are outlined in Appendix B. There are no volume or area sources included in the modeling analysis.

5.0 Modeling Methodology

Table 5-1 summarizes the key modeling parameters used in the impact analyses.

Table 5-1. Modeling Parameters

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Included in Section 2.1	Kootenai County is in attainment for all pollutants for which a NAAQS has been promulgated.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 19191.
Meteorological Data	Spokane, WA surface and upper air data	See Section 5.2 of this report for additional details of the meteorological data.
Terrain	Considered	See Section 5.3 of this report for additional details of the terrain.
Building Downwash	Considered	See Section 5.5 of this report for additional details of the building downwash.
NOx Chemistry	ARM2	AERMOD's Ambient Ratio Method, version 2 (ARM2) was used to model NO_x emissions.
Receptor Grid	**NAAQS Analyses**	
	Grid 1	Discrete receptors along the facility fenceline at 10-meter intervals.
	Grid 2	Cartesian receptors at a resolution of 50 meters from the property line outward to a distance of 1.0 kilometers.
	Grid 3	Cartesian receptors at a resolution of 100 meters from the property line outward to a distance of 2.0 kilometers.
	Grid 4	Cartesian receptors at a resolution of 250 meters from the property line outward to a distance of 5.0 kilometers.
	Grid 5	Cartesian receptors at a resolution of 500 meters from the property line outward to a distance of 10.0 kilometers.
	TAPs Analyses	
	Same as NAAQS	

5.1 Model Selection

GTN used the AMS/EPA Regulatory Model with Plume Rise Model Enhancements (AERMOD), version 19191 to complete the modeling analysis. The United States Environmental Protection Agency (USEPA) established AERMOD as the preferred air dispersion model in the agency's Guideline on Air Quality Models, 40 CFR 51 Appendix W. Non-default options were not used in this modeling analysis.

5.2 Meteorological Data

For refined modeling analyses, USEPA guidelines specify the use of either one (1) year of on-site meteorological data, or five (5) years of representative, hourly National Weather Service (NWS) observations. Because no on-site data existed, NWS data was relied upon in this analysis.

The meteorological data necessary for the AERMOD meteorological preprocessor (AERMET, version 19191) was based on hourly surface observation data and upper air sounding data from the from the Spokane, Washington station for meteorological years 2014 through 2018, respectively. This data was obtained via the National Oceanic and Atmospheric Administration (NOAA). The quality of the data is assumed to be adequate based on Idaho DEQ guidelines.

Meteorological sites were chosen based on the available data, the distance to the station, topography, and land use classification. Compressor Station 5 is primarily located in an area of flat terrain. The station also has an elevation of approximately 2,247 feet. The Spokane, Washington station is located in a rural area 67 km away with also relatively flat terrain and has an approximate elevation of 2,385 feet. Therefore, based on the availability of recent data, surrounding topography, distance to the station, and land use classification the Spokane, Washington station best represents Compressor Station 5. A wind rose is included in Appendix A.

The surface parameters (surface roughness, Bowen Ratio, and albedo) for the Spokane, Washington station was determined using AERSURFACE version 13016, which was run for dry, average, or wet conditions on a monthly basis for 12 evenly spaced sectors. The land use data was obtained from the United States Geological Survey (USGS) National Land Cover Data 1992 (NCLD92) archives. Monthly seasonal assignments and snow cover characterization was based on the following assumptions:

- Late Autumn/Winter without snow: December - February
- Winter with continuous snow: NA
- Transitional spring: March - April
- Midsummer: June - August
- Autumn: September – November

AREMINUTE (version 15272) was used to process 1-minute ASOS wind data to generate hourly average winds for input into AERMET.

An email attachment containing all electronic meteorological data files from the analysis are included with this report.

5.3 Effects of Terrain

Receptor and source elevations were determined using the AERMOD terrain processor (AERMAP), version 18081. The data available are GeoTIFF files broken down by county and are 1/3 arc-second resolution obtained from the National Elevation Dataset. The AERMAP domain matches the extent of the model domain, following the default settings. The datum of terrain data, building corner locations, emissions sources, and the ambient air boundary are specified and are consistent such that the modeled plot plan accurately represents the facility and surroundings.

5.4 Facility Layout

Figure 1 provided in Appendix A describes the facility layout of Compressor Station 5. The facility layout includes both the proposed and existing sources. The layout was prepared by GTN's engineering team.

5.5 Effects of Building Downwash

The Building Profile Input Program with Plume Rise Model Enhancements (BPIP-PRIME) version 04274 was used to calculate building downwash parameters for the model analysis. Locations for stacks and buildings will be put into BPIP-PRIME using the BPIP input file created from the site plan. Table 5-5-1 below describes the building dimensions which will be used in this modeling demonstration.

Table 5.5-1: Building Dimensions

Building ID	Description	X-Length (m)	Y-Length (m)	Eave Height (m)	Peak Height (m)
MTCBLDG	Motor Control Center Building	9.50	6.70	3.91	5.03
STRBLDG	Flammable Storage Building	7.61	6.70	3.91	5.03
WARBLDG	Warehouse Building	23.16	13.62	10.85	13.94
CTRLBLDG	Control Building	44.29	10.68	4.34	5.66
COMPBLDG2	Compressor Building No. 2	21.3	11.0	8.23	11.23
COMPBLDG3	Compressor Building No. 3	27.11	15.48	8.08	11.06

5.6 Ambient Air Boundary

For the purpose of defining ambient air, the "general public" is considered anyone not directly associated with the facility. General public access is precluded by a fence with a gate at Compressor Station 5. Therefore, the facility is assumed to be controlled and public access effectively precluded, and the ambient air boundary will be set at the fenceline. Figure 3 in Appendix A is included to described the proposed ambient air boundary.

5.7 Receptor Network

Receptor locations will follow Idaho DEQ guidelines. The receptors were based on a Cartesian receptor grid surrounding the facility with discrete receptors placed along the

ambient air boundary shown in Figure 2 in Appendix A. Receptors were not placed on GTN property.

Receptors include:

- Discrete receptors along the facility fenceline at 10-meter intervals;
- Cartesian receptors at a resolution of 50 meters from the property line outward to a distance of 1.0 kilometers;
- Cartesian receptors at a resolution of 100 meters from the property line outward to a distance of 2.0 kilometers;
- Cartesian receptors at a resolution of 250 meters from the property line outward to a distance of 5.0 kilometers; and
- Cartesian receptors at a resolution of 500 meters from the property line outward to a distance of 10.0 kilometers.

5.8 Background Concentrations

For the purposes of demonstrating modeled compliance with ambient standards, "background' values are required to estimate the total impact of sources under review. The background value represents the emission concentration resulting from distance sources and smaller region sources. The total ambient impact is estimated as the sum of the maximum modeled impact and the background value.

According to Idaho DEQ guidance, air monitoring data for the state can be obtained at the following EPA website address: http://www.epa.gov/air/data/indec.html, which is also known as the Environmental Protection Agency (EPA) Outdoor Air Quality Data webpage. Monitoring sites were chosen based on the available data, the distance to the station, topography, and surface wind characteristics. Table 5.8-1 below describes which monitor was chosen for each pollutant.

Table 5.8-1: Background Monitors

Pollutant	Monitor Name	Distance and Direction from Site
CO	Meridian – St. Luke's	900 km S
NO_2	Meridian – Near Road	480 km S
PM_{10}	Sandpoint	45 km NNE
$PM_{2.5}$	Bannock	660 km SE
SO_2	Meridian – St. Luke's	900 km S

Background concentrations were calculated from EPA data in the following manner according to DEQ guidelines:

- CO
  - 1-hour and 8-hour averaging period – the maximum 2nd highest monitored value over each year of applicable data
- NO_x
  - 1-hour averaging period – the maximum 3-year mean of the 98th percentile of the daily maximum 1-hour averaging concentrations over 1-year periods.
  - Annual averaging period – the maximum annual average for the applicable data. The most recent 5-year data set will be used.
- SO_2

    - 1-hour averaging period – the maximum 3-year mean of the 99th percentile of the daily maximum 1-hour averaging concentrations over 1-year periods.
    - 3-hour and 24-hour averaging period – the maximum 2nd highest monitored value over each year of applicable data.
    - Annual averaging period – the maximum annual average for the applicable data. The most recent 5-year data set will be used.
- PM_{10}
    - 24-hour averaging period – the maximum 2nd highest monitored value over each year of applicable data
- $PM_{2.5}$
    - 24-hour averaging period – the maximum 3-year mean of 98th percentile of 24-hour average concentrations over 1 -year periods.
    - Annual averaging period – the maximum 3-year mean of annual averages, using 5 consecutive years of data.

Background values used in the modeling demonstration are presented in the Section 6 of the report.

5.9 NO_x Chemistry

Please see Section 4.1.3 for NO_x chemistry discussion. Please note that OLM or PVMRM were not used in this analysis.

6.0 Results and Discussion

6.1 Criteria Pollutant Impact Results

6.1.1 Significant Impact Level Analyses

As previously mentioned, a SIL analysis was forgone based on agency direction.

6.1.2 Cumulative NAAQS Impact Analyses

Modeling of GTN's Compressor Station 5 potential emissions using AERMOD demonstrates compliance with the NAAQS for all pollutants and averaging periods. The predicted impacts for the previously mentioned pollutants including background concentrations were compared to the applicable air quality standards presented in Table 6.1.2-1 below. An email attachment containing all electronic modeling files from the analysis are included with this report.

Table 6.1.2-1: GTN Station 5 Results for Cumulative NAAQS Impact Analysis

Pollutant	Averaging Period	Project Impact (ug/m³)	Background Concentrations (ug/m³)	Total Impact (ug/m³)	NAAQS (ug/m³)	Percent of NAAQS
NO_x	1-hour	47.30	84.13	131.43	188	69.91%
	Annual	3.62	23.58	27.20	100	27.20%
CO	1-hour	94.84	1299.60	1394.44	40,000	3.49%
	8-hour	49.17	912.00	961.17	10,000	9.61%
PM_{10}	24-hour	0.88	98.40	99.28	150	66.19%
$PM_{2.5}$	24-hour	0.73	15.60	16.33	35	46.66%
	Annual	0.26	4.42	4.68	12	39.02%
SO_2	1-hour	23.18	9.43	32.61	196	16.64%
	3-hour	21.49	12.26	33.75	1300	2.60%
	24-hour	7.16	4.24	11.41	365	3.12%
	Annual	2.05	1.33	3.38	80	4.23%

6.2 TAP Impact Analyses

Modeling of GTN's Compressor Station 5 potential emissions using AERMOD demonstrates compliance with the AAC or AACC for all applicable TAP pollutants and averaging periods. Modeling results are provided in Table 6.2-1.

Table 6.2-1: GTN Station 5 Results for TAP Impacts Analyses

TAP	Averaging Period	Maximum Modeled Impact (µg/m³)[a]	AAC or AACC (µg/m³)
1,3-Butadiene	Annual	0.00	3.60E-03
Acetaldehyde	Annual	3.40E-04	4.50E-01
Benzene	Annual	6.97E-02	1.20E-01
Formaldehyde	Annual	6.17E-03	7.70E-02
PAH	Annual	3.50E-04	1.40E-02

a. Micrograms/cubic meter.

7.0 Quality Assurance/Control

All quality assurance/control measures outlined in Section 7 of Idaho DEQ's modeling guidance were followed to minimize error in the submitted analyses.

Appendix A

Figures:

1. Facility plot plan with emission points and buildings labeled.
2. Kootenai County 2020 Comprehensive Plan Land Use Map.
3. Ambient Air Boundary.
4. Receptor Grid.
5. Wind Rose.

Facility Plot Plan with Emission Points



Figure 1

Facility Plot Plan with Buildings



Figure 2

Future Land Use Map

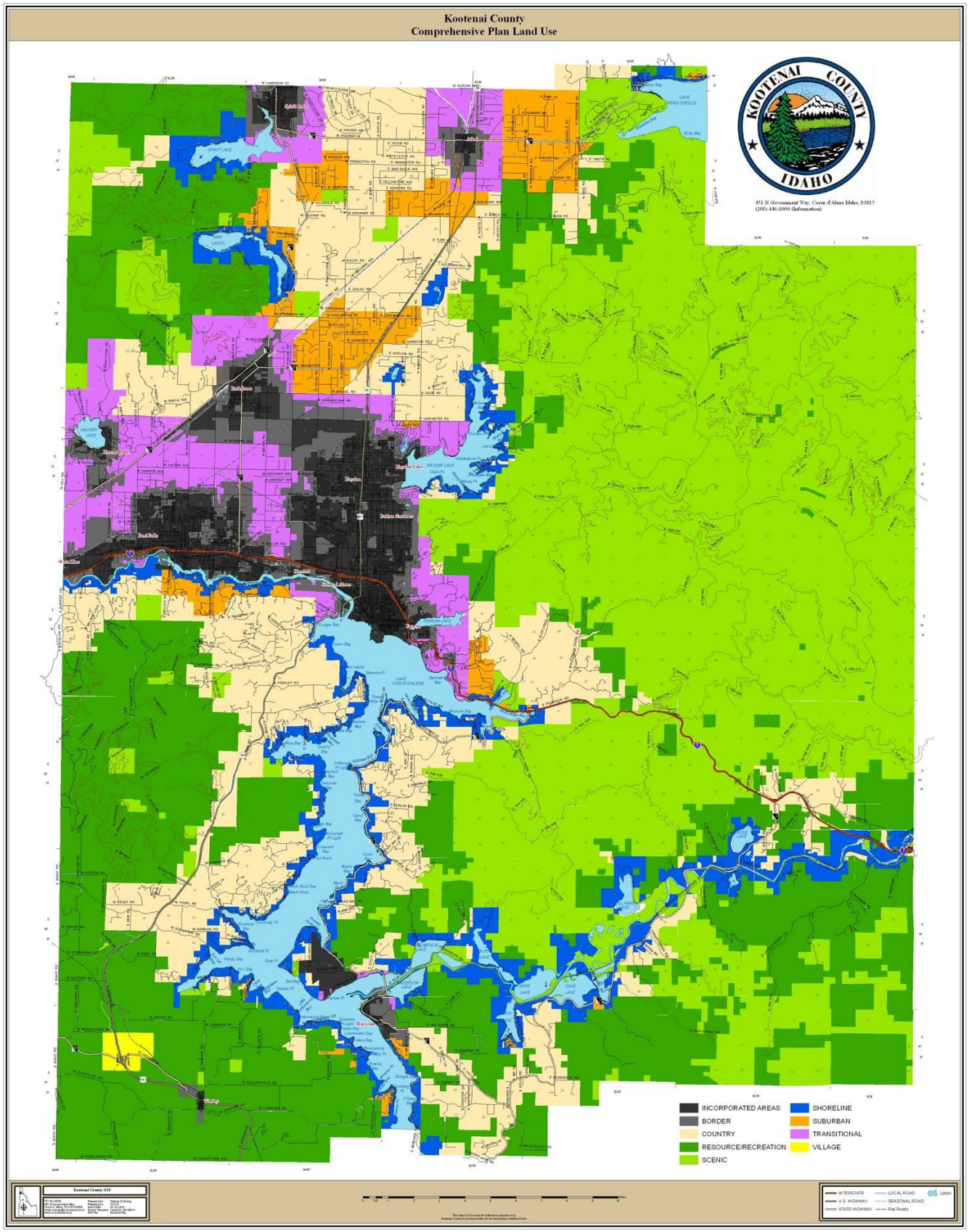


Figure 3

Ambient Air Boundary



Figure 4

Receptor Grid



Figure 5

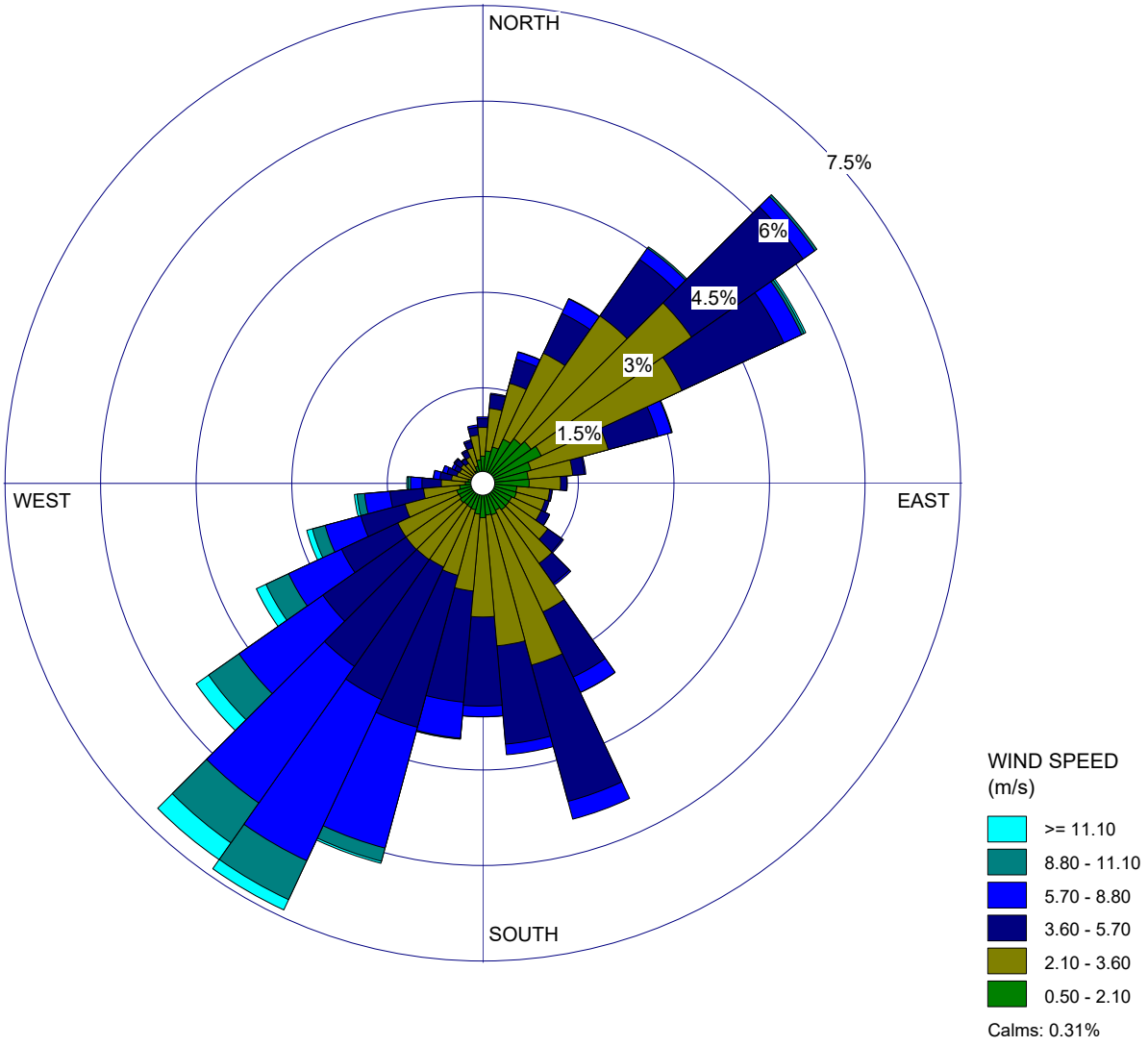
Wind Rose

WIND ROSE PLOT:

Station #24157 - SPOKANE/INT'L ARPT, WA

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **Start Date: 1/1/2014 - 00:00** **End Date: 12/31/2018 - 23:59**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.31%**	TOTAL COUNT: **43758 hrs.**	
	AVG. WIND SPEED: **3.99 m/s**	DATE: **4/14/2020**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 6

Appendix B

Stack Discharge Parameters and Emission Rates

Gas Transmission Northwest
Compressor Station 5

Stack Locations for Modeling Project Impacts

Unit ID	Description	Location		Base Elev. (m)	Basis
		x (m E)	y (m N)		
5D	New Solar Titan 130 Turbine	518,293.34	5,307,092.65	745.09	Provided by GTN; AERMAP Terrain Processor
5C	Cooper Cobbera	518,270.75	5,307,066.11	745.25	Provided by GTN; AERMAP Terrain Processor
FG1	Fuel Gas Heater	518,337.57	5,307,129.06	745.40	Provided by GTN; AERMAP Terrain Processor

Gas Transmission Northwest
Compressor Station 5

Stack Parameters for Modeling Project Impacts

Unit ID	Scenario	Release Height (m)	Stack Temp. (K)	Stack Dia. (m)	Stack Exit Vel. (m/s)	Stack Exit Flow (acfm)	Basis
5D (NEW)	Short & Long-Term (32°F)	14.630	752.594	3.439	13.030	256,357	Release Height - 48 ft (Provided by GTN based on vendor information) Stack Diameter - Diameter based on vendor information (10' x 10') All Else - Solar Titan Spec Sheet from vendor
5C	Tested values	14.146	704.817	3.131	27.233	444,104	All stack parameters are based on information provided by Environmental Quality Management, Inc. engineering test conducted in May 2020.
FG1 (NEW)	-	4.572	352.039	0.762	0.859	830	Release Height - 15 ft (Provided by GTN based on vendor information) Stack Diameter - Diameter based on vendor information (2.5') All Else - Based on vendor information

Gas Transmission Northwest
Compressor Station 5

Criteria Pollutant Emission Rates for Modeling Project Impacts

Unit ID	CO (g/s)		NOx (g/s)		PM10/PM2.5 (g/s)		SO2 (g/s)		Basis
	Short-Term (59°F)	Long-Term (59°F)	Short-Term (59°F)	Long-Term (59°F)	Short-Term (59°F)	Long-Term (59°F)	Short-Term (59°F)	Long-Term (59°F)	
5D	1.174	N/A	1.157	1.157	0.141	0.141	1.222	1.222	See source-source specific emissions calculations provided in Appendix B of the permit application.
5C	4.108	N/A	5.668	5.668	8.653E-02	8.653E-02	0.110	0.110	See source-source specific emissions calculations provided in Appendix B of the permit application.
FG1	1.038E-02	N/A	1.235E-02	1.24E-02	9.388E-04	9.388E-04	7.194E-03	7.194E-03	See source-source specific emissions calculations provided in Appendix B of the permit application.

Gas Transmission Northwest
Compressor Station 5

TAPS Emission Rates for Modeling Project Impacts

Unit ID	1,3 -Butadiene (g/s)	Acetaldehyde (g/s)	Benzene (g/s)	Formaldehyde (g/s)	PAH (g/s)	Basis
5D	9.199E-06	8.557E-04	2.567E-04	1.519E-02	4.706E-05	See source-source specific emissions calculations provided in Appendix B of the permit application.
5C	1.657E-05	1.542E-03	4.625E-04	2.736E-02	8.479E-05	See source-source specific emissions calculations provided in Appendix B of the permit application.
FG1	0.000E+00	0.00E+00	2.594E-07	9.265E-06	1.112E-09	See source-source specific emissions calculations provided in Appendix B of the permit application.



Responsive partner.
Exceptional outcomes.

Toll Free: 800-472-2232 **Email: wenckmp@wenck.com** **Web: wenck.com**