Statement of Basis

Permit to Construct No. P-2010.0182
Project ID 62235

Nampa Waste Water Treatment Plant
Nampa, Idaho

Facility ID 027-00110

Final

November 13, 2019
Morrie Lewis
Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
Btu	British thermal units
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
HAP	hazardous air pollutants
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pounds per hour
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
O_2	oxygen
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
PTC	permit to construct
PTE	potential to emit
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12-calendar-month period
TAP	toxic air pollutants
VOC	volatile organic compounds
WWTP	waste water treatment plant

FACILITY INFORMATION

Description

The City of Nampa operates a Waste Water Treatment Plant (WWTP) to manage and treat industrial and municipal wastewater. The facility previously had five anaerobic digesters, of which, three are primary digesters and two are secondary digesters. The city has proposed building a fourth primary digester with equivalent capacity of the other three primary anaerobic digesters and restricting the two secondary digesters to only be used for storage of biogas and stabilized biosolids. The two secondary digesters have no temperature control or mixing capability necessary to function as digesters, but do have floating covers that can flex with biogas pressurization changes. Therefore, the permittee will only use the secondary digesters for storage.

Biogas will be generated by the primary anaerobic digesters, only. The typical composition of biogas ranges from 55% to 60% methane (CH_4), 40% to 45% carbon dioxide (CO_2), and less than 1% hydrogen sulfide (H_2S). The accumulated biogas is collected and conveyed via piping to four dual-fuel fired boilers. The boilers use biogas as the primary fuel and natural gas as the secondary fuel. The biogas is combusted in the boilers to produce steam for heat for use in the anaerobic digesters. Any excess biogas produced is conveyed to the candlestick flare, mixed with atmospheric oxygen, and combusted. The City of Nampa has a biogas production limit of 1,050,000 standard cubic feet per day (scf/day). In addition, the proposed limit for the hydrogen sulfide (H_2S) concentration entering each boiler from the anaerobic digesters is 1,200 parts per million by volume (ppmv), based on monitored values obtained by the hydrogen sulfide monitor.

Three diesel-fired emergency standby IC engines powering electrical generators are used to supply emergency backup power to the entire WWTP facility. The three emergency IC engines are located in a stand-alone building near the southern perimeter of the facility. Each IC engines has a separate horizontal exhaust stack that exits out the top of the building in a 90 degree angle towards the primary digesters to the north. The City of Nampa is requesting to permit each generator to run a maximum of 100 hours per year for testing and maintenance and required regulatory purposes. Generator maintenance and testing will be limited to 6 hours per day to account for load bank testing. A 3,000 gallon above ground storage tank (AST) is used to store ultralow sulfur diesel fuel for the emergency generators.

There are eight natural gas-fired heaters located in two of the shop bays (4 space heaters in each shop bay). The space heaters are used for comfort heating in the winter months.

There is also one direct fired natural gas-fired gas pressure washer located in the Truck Shop that is used intermittently for cleaning purposes.

Permitting History

The following information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

November 13, 2019	P-2010.0182 Project 62235, add an anaerobic digester and flare, and re-characterize existing digester, boiler, and flare emissions. (A)
October 19, 2018	P-2010.0182 Project 62111, add anaerobic digester. (S)
May 4, 2018	P-2010.0182 Project 62022 boiler replacement. (S)
April 24, 2011	P-2010.0182 Project 60668, initial permit re-issued due to typographical error. (S)
April 4, 2011	P-20100182 Project 60668, initial permit. (S)

Application Scope

This PTC is for a minor modification at an existing minor facility.

The applicant has proposed to:

- Modify the existing permit to add an anaerobic digester and flare, and re-characterize existing digester, boiler, and flare emissions.

Application Chronology

May 14, 2019	DEQ received an application and an application fee.
May 20 – June 4, 2019	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
June 10, 2019	DEQ determined that the application was incomplete.
June 18, 2019	DEQ received supplemental information from the applicant.
July 17, 2019	DEQ determined that the application was incomplete.
August 7, 2019	DEQ met with the applicant to discuss draft responses to items in the incompleteness letter, including boiler load, derivation of stack release parameters, model receptor spacing, and ferric chloride dosing for H_2S control.
August 8 and 15, 2019	DEQ received supplemental information from the applicant, including updated emission inventories and modeling analyses.
August 30, 2019	DEQ determined that the application was complete.
October 18, 2019	DEQ made available the draft permit and statement of basis for peer and regional office review.
October 24, 2019	DEQ made available the draft permit and statement of basis for applicant review.
November 8, 2019	DEQ received the permit processing fee.
November 13, 2019	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNITS AND CONTROL EQUIPMENT

Source	Control Equipment
Primary Anaerobic Digester #1 Storage capacity: 881,000 gallons Gas generation capacity: 213,432 scf/day Installation date: 1964	Boiler #1 Boiler #2 Boiler #3 Boiler #4 Flare #1 Flare #2 Iron Salt Dosing Control Equipment (Ferric Chloride)
Primary Anaerobic Digester #2 Storage capacity: 881,000 gallons Gas generation capacity: 213,432 scf/day Installation date: 1980	
Primary Anaerobic Digester #3 Storage capacity: 881,000 gallons Gas generation capacity: 234,408 scf/day Installation date: 2010	
Primary Anaerobic Digester #4 Storage capacity: 881,000 gallons Gas generation capacity: 234,408 scf/day Installation date: 2019	
Primary Anaerobic Digester #5 Storage capacity: 881,000 gallons Gas generation capacity: 234,408 scf/day Installation date: 2020	
Secondary Anaerobic Digester #1 Storage capacity: 433,000 gallons Installation date: 1948	
Secondary Anaerobic Digester #2 Storage capacity: 433,000 gallons Installation date: 1948	

Source	Control Equipment
Boiler #1 Manufacturer: Burnham Model: 4FHW 311A 50DG NG WEB Heat input capacity: 2.603 MMBtu/hr Fuel: biogas and natural gas only Installation date: 2012	N/A
Boiler #2 Manufacturer: Burnham Commercial Model: 4FW 311A 50DG NG WEB Heat input capacity: 2.603 MMBtu/hr Steam generation capacity: 1,000 lb/hr Fuel: biogas and natural gas only Installation date: 2008	N/A
Boiler #3 Manufacturer: Burnham Commercial Model: 4FW 311A 50DG NG WEB Heat input capacity: 2.603 MMBtu/hr Steam generation capacity: 1,000 lb/hr Fuel: biogas and natural gas only Installation date: 2010	N/A
Boiler #4 Manufacturer: Burnham Commercial Model: 4FW 311A 50DG NG WEB Heat input capacity: 2.603 MMBtu/hr Steam generation capacity: 1,000 lb/hr Fuel: biogas and natural gas only Installation date: 2010	N/A
Flare #1 Manufacturer: Varec Model: WG 244WS01912119S6 Heat input capacity: 14.125 MMBtu/hr Installation date: 2010	N/A
Flare #2 Manufacturer: Varec Model: 244WS Heat input capacity: 14.125 MMBtu/hr Installation date: 2020	N/A
Emergency IC Engine #1 Manufacturer: Caterpillar Model: C27 Serial #: MJE01635 Maximum power rating: 1,190 bhp Maximum operation: 6 hr/day and 100 hr/yr (non-emergency) Tier certification: 2 Fuel: diesel fuel only Installation date: 2009	N/A
Emergency IC Engine #2 Manufacturer: Caterpillar Model: C27 Serial #: MJE01769 Maximum power rating: 1,190 bhp Maximum operation: 6 hr/day and 100 hr/yr (non-emergency) Tier certification: 2 Fuel: diesel fuel only Installation date: 2009	N/A

Source	Control Equipment
Emergency IC Engine #3 Manufacturer: Caterpillar Model: C27 Serial #: MJE01770 Maximum power rating: 1,190 bhp Maximum operation: 6 hr/day and 100 hr/yr (non-emergency) Tier certification: 2 Fuel: diesel fuel only Installation date: 2009	N/A
Heater #1 Manufacturer: Sterling Model: QVSF Heat input capacity: 0.200 MMBtu/hr Fuel: natural gas only Installation date: 2009	N/A
Heater #2 Manufacturer: Sterling Model: QVSF Heat input capacity: 0.200 MMBtu/hr Fuel: natural gas only Installation date: 2009	N/A
Heater #3 Manufacturer: Sterling Model: QVSF Heat input capacity: 0.200 MMBtu/hr Fuel: natural gas only Installation date: 2009	N/A
Heater #4 Manufacturer: Sterling Model: QVSF Heat input capacity: 0.200 MMBtu/hr Fuel: natural gas only Installation date: 2009	N/A
Heater #5 Manufacturer: ADP Model: SEP Heat input capacity: 0.145 MMBtu/hr Fuel: natural gas only Installation date: 2001	N/A
Heater #6 Manufacturer: ADP Model: SEP Heat input capacity: 0.145 MMBtu/hr Fuel: natural gas only Installation date: 2001	N/A
Heater #7 Manufacturer: ADP Model: SEP Heat input capacity: 0.145 MMBtu/hr Fuel: natural gas only Installation date: 2001	N/A
Heater #8 Manufacturer: ADP Model: SEP Heat input capacity: 0.145 MMBtu/hr Fuel: natural gas only Installation date: 2001	N/A
Pressure Washer Heater Manufacturer: Hotsy Model: S5735-3 Heat input capacity: 0.657 MMBtu/hr Fuel: natural gas only Installation date: 1998	N/A

Emission Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit (PTE) as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of PTE, a facility-wide emission inventory was developed for the boilers, the flares, the emergency IC engines, the heaters, and the pressure washer heater at the facility (see Appendix A). Emissions estimates of criteria pollutant, HAP PTE were based on manufacturer specifications, emission factors from AP-42, operation of 8,760 hours per year, proposed biogas sulfur content limits (700 ppm), and process information specific to the facility for this proposed project.

Pre-Project PTE

Pre-project PTE is used to establish the change in emissions at a facility as a result of this project.

The following table presents the pre-project potential to emit for all criteria pollutants from all emissions units at the facility as submitted by the applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 2 PRE-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_x		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Boiler #1[c]	0.06	0.27	1.72	7.52	0.72	3.17	0.92	4.02	0.10	0.43
Boiler #2[c]	0.07	0.31	1.99	8.70	0.84	3.67	1.06	4.65	0.11	0.50
Boiler #3[c]	0.07	0.31	1.99	8.70	0.84	3.67	1.06	4.65	0.11	0.50
Boiler #4[c]	0.07	0.31	1.99	8.70	0.84	3.67	1.06	4.65	0.11	0.50
Flare #1	0.07	0.29	1.55	6.79	0.42	1.83	2.27	9.93	0.39	1.69
Emergency IC Engine #1	0.13	0.03	0.01	0.00	17.02	4.26	1.13	0.28	0.15	0.04
Emergency IC Engine #2	0.13	0.03	0.01	0.00	17.02	4.26	1.13	0.28	0.15	0.04
Emergency IC Engine #3	0.13	0.03	0.01	0.00	17.02	4.26	1.13	0.28	0.15	0.04
Heater #1	0.001	0.0065	0.000	0.0005	0.020	0.0858	0.016	0.0721	0.001	0.0047
Heater #2	0.001	0.0065	0.000	0.0005	0.020	0.0858	0.016	0.0721	0.001	0.0047
Heater #3	0.001	0.0065	0.000	0.0005	0.020	0.0858	0.016	0.0721	0.001	0.0047
Heater #4	0.001	0.0065	0.000	0.0005	0.020	0.0858	0.016	0.0721	0.001	0.0047
Heater #5	0.001	0.0047	0.000	0.0004	0.014	0.0622	0.012	0.0522	0.001	0.0034
Heater #6	0.001	0.0047	0.000	0.0004	0.014	0.0622	0.012	0.0522	0.001	0.0034
Heater #7	0.001	0.0047	0.000	0.0004	0.014	0.0622	0.012	0.0522	0.001	0.0034
Heater #8	0.001	0.0047	0.000	0.0004	0.014	0.0622	0.012	0.0522	0.001	0.0034
Pressure Washer	0.005	0.0214	0.000	0.0017	0.064	0.2821	0.054	0.2369	0.004	0.0155
Pre-Project Totals	**0.74**	**1.65**	**9.27**	**40.42**	**54.92**	**29.66**	**9.93**	**29.47**	**1.28**	**3.79**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
c) Boilers #1 thru #4 are fired on biogas and natural gas. Therefore, the uncontrolled PTE was the worst-case on a pollutant-by-pollutant basis for the two fuels.

Post-Project PTE

Post-project PTE is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post-project PTE includes all permit limits resulting from this project.

The following table presents the post-project PTE for criteria pollutants from all emissions units at the facility as submitted by the applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 3 POST-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_x		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Boiler #1[c]	0.033	0.14	0.51	2.21	0.25	1.11	0.10	0.43	0.02	0.08
Boiler #2[c]	0.033	0.14	0.51	2.21	0.25	1.11	0.10	0.43	0.02	0.08
Boiler #3[c]	0.033	0.14	0.51	2.21	0.25	1.11	0.10	0.43	0.02	0.08
Boiler #4[c]	0.033	0.14	0.51	2.21	0.25	1.11	0.10	0.43	0.02	0.08
Flare #1	0.179	0.78	2.43	10.62	0.96	4.21	5.23	22.89	0.85	3.71
Flare #2	0.179	0.78	2.43	10.62	0.96	4.21	5.23	22.89	0.85	3.71
Emergency IC Engine #1	0.120	0.01	0.02	0.001	15.89	0.79	1.15	0.06	0.14	0.01
Emergency IC Engine #2	0.120	0.01	0.02	0.001	15.89	0.79	1.15	0.06	0.14	0.01
Emergency IC Engine #3	0.120	0.01	0.02	0.001	15.89	0.79	1.15	0.06	0.14	0.01
Heater #1	0.002	0.0065	0.0002	0.0006	0.02	0.09	0.02	0.08	0.001	0.005
Heater #2	0.002	0.0065	0.0002	0.0006	0.02	0.09	0.02	0.08	0.001	0.005
Heater #3	0.002	0.0065	0.0002	0.0006	0.02	0.09	0.02	0.08	0.001	0.005
Heater #4	0.002	0.0065	0.0002	0.0006	0.02	0.09	0.02	0.08	0.001	0.005
Heater #5	0.002	0.0047	0.0002	0.0004	0.01	0.07	0.01	0.06	0.001	0.004
Heater #6	0.002	0.0047	0.0001	0.0004	0.01	0.07	0.01	0.06	0.001	0.004
Heater #7	0.002	0.0047	0.0001	0.0004	0.01	0.07	0.01	0.06	0.001	0.004
Heater #8	0.002	0.0047	0.0001	0.0004	0.01	0.07	0.01	0.06	0.001	0.004
Pressure Washer	0.005	0.0214	0.0004	0.002	0.07	0.29	0.06	0.24	0.004	0.02
Above-Ground Storage Tank	0.000	0.0000	0.0000	0.0000	0.00	0.00	0.000	0.0000	0.000112	0.00000006
Post-Project Totals	**0.87**	**2.22**	**6.96**	**30.09**	**50.78**	**16.16**	**14.49**	**48.48**	**2.21**	**7.83**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
c) Boilers #1 thru #4 are fired on biogas and natural gas. Therefore, the uncontrolled PTE was the worst-case on a pollutant-by-pollutant basis for the two fuels.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants as submitted by the applicant and verified by DEQ staff.

Table 4 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_x		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	0.74	1.65	9.27	40.42	54.92	29.66	9.93	29.47	1.28	3.79
Post Project Potential to Emit	0.87	2.22	6.96	30.09	50.78	16.16	14.49	48.48	2.21	7.83
Changes in Potential to Emit	**0.13**	**0.57**	**-2.31**	**-10.33**	**-4.14**	**-13.50**	**4.56**	**19.01**	**0.93**	**4.04**

Post-Project TAP Emissions

The following table presents the facility-wide PTE for TAP as submitted by the applicant and verified by DEQ staff.

Table 5 FACILITY-WIDE TAP PTE

Non-Carcinogenic Toxic Air Pollutants	Post-Project 24-hour Average Emissions Rates (lb/hr)	Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
3-Methylchloranthrene	2.20E-08	2.50E-06	No
Acetaldehyde	6.75E-06	3.00E-03	No
Acrolein	4.62E-05	1.70E-02	No
Ammonia	1.51E-01	1.20E+00	No
Benzene	7.70E-03	8.00E-04	Yes
Benzo(a)pyrene	8.35E-08	2.00E-06	No
Formaldehyde	5.52E-02	5.10E-04	Yes
Hexane	2.20E-02	1.20E+01	No
Hydrogen Sulfide	2.87E-01	9.33E-01	No
Naphthalene	7.70E-04	3.33E+00	No
Pentane	3.17E-02	1.18E+02	No
Toluene	1.69E-03	2.50E+01	No
Xylenes	1.13E-03	2.90E+01	No
Naphthalene (as PAH) [(a)]	4.11E-05	9.10E-05	No
POM (7-PAH) [(b)]	1.39E-07	2.00E-06	No
Arsenic	2.44E-06	1.50E-06	Yes
Barium	5.09E-05	3.30E-02	No
Beryllium	1.39E-07	2.80E-05	No
Cadmium	1.34E-05	3.70E-06	Yes
Chromium	1.62E-05	3.30E-02	No
Cobalt	9.71E-07	3.30E-03	No
Copper	9.83E-06	1.30E-02	No
Manganese	4.39E-06	6.70E-02	No
Mercury	3.01E-06	1.00E-03	No
Molybdenum	1.27E-05	3.33E-01	No
Nickel	2.43E-05	2.75E-05	No
Selenium	2.77E-07	1.30E-02	No
Vanadium	2.66E-05	3.00E-03	No
Zinc	3.35E-04	3.33E-01	No

a) Polycyclic aromatic hydrocarbons, with the exception of POM (7-PAH).
b) Polycyclic Organic Matter is the sum of benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene.

With the exception of benzene, formaldehyde, arsenic, and cadmium, all changes in emissions rates for TAP were below the screening emissions level (EL) as a result of this project. Therefore, modeling was required for benzene, formaldehyde, arsenic, and cadmium.

Post-Project HAP Emissions

The following table presents the PTE for HAP as submitted by the applicant and verified by DEQ staff.

Table 6 FACILITY-WIDE HAP PTE

Hazardous Air Pollutants	PTE (T/yr)
Acetaldehyde	2.96E-05
Acrolein	2.03E-04
Benzene	3.37E-02
Formaldehyde	2.42E-01
Hexane	9.62E-02
Hydrogen Sulfide	1.26E+00
Naphthalene	3.37E-03
Toluene	7.41E-03
Xylene	4.96E-03
POM	6.09E-07
Arsenic	1.01E-05
Beryllium	6.08E-07
Cadmium	5.57E-05
Chromium	7.09E-05
Cobalt	4.25E-06
Manganese	1.92E-05
Mercury	1.32E-05
Nickel	1.06E-04
Selenium	1.22E-06
Total	**1.65**

Ambient Air Quality Impact Analyses

As presented in the modeling memo in Appendix B, the estimated emission increases of sulfur dioxide (SO_2), particulate matter ($PM_{2.5}$ and PM_{10}), oxides of nitrogen (NO_x), benzene, formaldehyde, arsenic, and cadmium from this project exceeded published DEQ modeling thresholds and applicable screening emission levels (EL) established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline.[1] Refer to the Emission Inventories section for additional information concerning the emission inventories.

The applicant provided facility-wide modeling compliance demonstrations for emissions of the pollutants identified above. The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emission increases due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP).

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

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[1] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011 (September 2013), September 2013, criteria pollutant BRC thresholds as provided in IDAPA 58.01.01.221.01, and DEQ guidance pertaining to BRC (2009ACF12).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Canyon County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For HAP (Hazardous Air Pollutants) Only:

A = Use when any one HAP has actual or potential emissions ≥ 10 T/yr or if the aggregate of all HAP (Total HAP) has actual or potential emissions ≥ 25 T/yr.

SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits ≥ 8 T/yr of a single HAP or ≥ 20 T/yr of THAP.

SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.

B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table 7 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	2.22	**100**	B
PM_{10}	2.22	**100**	B
$PM_{2.5}$	2.22	**100**	B
SO_2	30.09	**100**	B
NO_x	16.16	**100**	B
CO	48.48	**100**	B
VOC	7.83	**100**	B
HAP (single)	1.26E+0	**10**	B
HAP (total)	1.65	**25**	B
Pb	1E-04	**100**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 .... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility to add an anaerobic digester and flare, and re-characterize existing digester, boiler, and flare emissions. Therefore, a permit to construct is required in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 .... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301 .... Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility do not have a potential to emit greater than 100 tons per year for $PM_{2.5}$, PM_{10}, SO_2, NO_x, CO, and VOC or 10 tons per year for any one HAP or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006 and the requirements of IDAPA 58.01.01.301 were not applicable.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 .... Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

The engines are affected sources subject to NSPS in 40 CFR 60, for which applicability determinations were provided in P-2010.0182 Project 62022. This permitting action does not alter the applicability status of these existing affected sources at the facility.

- 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. DEQ is delegated this Subpart. All three CI IC engines at this facility were manufactured in 2009 with displacement of 6.8 l/cylinder.

The requirements of Subpart IIII were incorporated in this permitting action (Permit Conditions 3.4, 3.8–3.12, and 3.16–3.19).

This facility is not subject to any other NSPS requirements as a result of this project. The boilers are each below the heat input applicability threshold of 10 MMBtu/hr, and are therefore not subject to Subpart Dc requirements.

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61 as a result of this project.

MACT/GACT Applicability (40 CFR 63)

The facility is not subject to any NESHAP requirements in 40 CFR 63 as a result of this project. The boilers are gas-fired (biogas), and are therefore not subject to NESHAP Subpart JJJJJJ requirements. Because the engines are subject to NSPS Subpart IIII, nothing further is required under NESHAP Subpart ZZZZ.

Permit Conditions Review

This section describes those permit conditions that have been added, revised, modified or deleted as a result of this permitting action. Though included in the Emission Inventories, the above-ground diesel fuel storage tank (3,000 gal) was not listed as a permitted emissions unit in Table 1.1 of the permit, consistent with DEQ policy and because emissions were below 10% of below regulatory concern (BRC) thresholds.[1]

Revised Permit Conditions 1.4, 2.1, 2.2, 2.4, 2.7, 2.8, 2.10–2.11, 2.13, and 2.19 (existing *Permit Conditions 1.4,2.1, 2.2, 2.4, 2.7–2.8, 2.10–2.13, and 2.16–2.17 of P-2010.0182 Project 62111 issued 10/19/18)*

Minor updates to Table 1.1, Table 2.1, and process descriptions and existing limits were made to accommodate addition of the flare and primary digester.

Established Permit Condition 2.12

This permit condition establishes operational limits concerning boiler partial load operation and requirements for removal of boiler stack rain caps. These limits were based on assumptions relied upon in the ambient air quality impact analyses (see Appendix B). Because a modeling scenario reflecting simultaneous boiler combustion of partial load on biogas with the balance made up of natural gas was not evaluated, it is assumed that at any time biogas is not used as a primary fuel, that only natural gas will be fired.

Revised Permit Condition 2.3, 2.6, 2.9, and 2.18 (existing *Permit Conditions 2.3, 2.6, 2.9, and 2.15 of P-2010.0182 Project 62111 issued 10/19/18)*

The emissions from the boilers and candlestick flare stacks shall not exceed any corresponding emissions rate limits listed in the following table.

Table 2.2 Boiler and Flare Emission Limits (a)

Source Description	PM_{10} (b)		SO_2		NO_X		CO		VOC	
	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)
Boiler #1	0.06	0.27	1.72	7.52	0.72	3.17	0.92	4.02	0.10	0.43
Boiler #2	0.07	0.31	1.99	8.70	0.84	3.67	1.06	4.65	0.11	0.50
Boiler #3	0.07	0.31	1.99	8.70	0.84	3.67	1.06	4.65	0.11	0.50
Boiler #4	0.07	0.31	1.99	8.70	0.84	3.67	1.06	4.65	0.11	0.50
Candlestick Flare	0.07	0.29	1.55	6.79	0.42	1.83	2.27	9.93	0.39	1.69

a *In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.*

b *Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.*

c *Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.*

d *Tons per any consecutive 12-calendar month period.*

The average annual concentration of hydrogen sulfide (H_2S) of the biogas entering the boilers and the flare shall not exceed 1,200 ppmv.

Biogas production from the anaerobic digesters and combusted in Boiler #1, Boiler #2, Boiler #3, Boiler #4, and the Candlestick Flare shall not exceed 1,050,000 scf/day, based on the average scf combusted per day over any consecutive 12 month period.

Unless an alternative monitoring and recordkeeping method is approved by DEQ, the permittee shall comply with the following requirements to determine the concentration of H_2S in the gas stream produced by the anaerobic digester:

- *The H_2S biogas concentration shall be measured downstream of the digesters and upstream of the boilers and the flare. Use of a Draeger tube as a method for monitoring biogas H_2S concentration has been approved by DEQ. The Draeger tube sampling shall be conducted in accordance with the O&M manual and the manufacturer specifications.*
- *Calibration of the H_2S concentration monitor shall be performed no less frequently than semi-annually and recorded in accordance with the O&M manual.*

The H_2S concentrations from the monitor shall be recorded once per week.

Monitoring and recordkeeping of H_2S concentrations shall occur weekly during operation of the digester. Monthly monitoring may be conducted in lieu of weekly monitoring, provided that 24 consecutive weeks of monitoring show that the measured H_2S concentration does not equal or exceed 90% of 1,200 ppmv (1,080 ppmv). If any measured H_2S concentration during monthly monitoring equals or exceeds 1,080 ppmv, then the monitoring frequency shall revert to weekly until 24 consecutive weeks of monitoring do not equal or exceed 1,080 ppmv. Records of this information shall be maintained on site and be made available to DEQ representatives upon request and in accordance with the Monitoring and Recordkeeping general provision.

Emission limits (reduced) and production limits (increased) for biogas combusted in the boilers and flares and associated monitoring were updated consistent with the emission rates used in modeling compliance demonstrations. Corresponding values concerning monitoring frequency were also updated. These changes were permitted by the addition of iron salt (ferric chloride) dosing control equipment.

Established Permit Condition 2.14–2.16, and 2.20

Requirements to ensure proper operation and maintenance of control equipment were established consistent with information provided in the application. The applicant committed to installation and operation of flares consistent with the requirements of 40 CFR 60.13; installation and operation of iron salt (ferric chloride) dosing equipment consistent with manufacturer's recommendations and to ensure adequate control of H_2S emissions (e.g., input of at least 50 kg/ton feed); and monitoring of H_2S concentration to demonstrate compliance.

Revised Permit Condition 3.3 (existing *Permit Condition 3.3 of P-2010.0182 Project 62111 issued 10/19/18)*

The emissions from the IC Engines #1, #2, and #3 stacks shall not exceed any corresponding emissions rate limits listed in the following table.

Table 3.2 IC Engines #1, #2, and #3 Emission Limits [(a)]

Source Description	PM_{10} [(b)]		SO_2		NO_X		CO		VOC	
	lb/hr [(c)]	T/yr [(d)]	lb/hr [(c)]	T/yr [(d)]	lb/hr [(c)]	T/yr [(d)]	lb/hr [(c)]	T/yr [(d)]	lb/hr [(c)]	T/yr [(d)]
IC Engine #1	0.13	0.03	0.01	0.00	17.02	4.26	1.13	0.28	0.15	0.04
IC Engine #2	0.13	0.03	0.01	0.00	17.02	4.26	1.13	0.28	0.15	0.04
IC Engine #3	0.13	0.03	0.01	0.00	17.02	4.26	1.13	0.28	0.15	0.04

a In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.

b Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.

c Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.

d Tons per any consecutive 12-calendar month period.

Emission limits for the engines were updated consistent with the emission rates used in modeling compliance demonstrations.

Revised Permit Condition 3.1–3.2, 3.5, and 3.13 (existing Permit Conditions 3.1–3.2, 3.4–3.9, 3.12, and 3.14 of P-2010.0182 Project 62111 issued 10/19/18)

Minor updates to these permit conditions were made, with references to "internal combustion" (IC) terminology considered unnecessary and removed.

Revised Permit Condition 4.2, and established Permit Conditions 3.4, 3.8–3.12, and 3.16–3.19, and 4.1 (existing *Permit Condition 2.11 of P-2010.0182 Project 62111 issued 10/19/18)*

> *The permittee shall comply with the requirements of 40 CFR 60 – General Provisions according to the requirements of 40 CFR 60, IIII for Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.*

These permit conditions incorporate applicable NSPS Subparts A and IIII requirements. Although the engines were previously applicable to these requirements, explicit requirements were not previously established as permit conditions. Although not required by NSPS, the applicant has also committed to operating and maintaining the flares in accordance with the requirements of 40 CFR 60.18(b) through (e).

Removed existing Permit Conditions 2.18 and 3.15 of P-2010.0182 Project 62111 issued 10/19/18

> *All monitoring and recordkeeping documentation required by this permit shall be maintained in accordance with the Monitoring and Recordkeeping general provision.*

> *All monitoring and recordkeeping documentation required by this permit shall be maintained in accordance with the Recordkeeping general provision.*

These permit conditions were considered duplicative of the Monitoring and Recordkeeping general provision, and were removed.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c. During this time, there was not a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

APPENDIX A – EMISSION INVENTORIES

Table 1. Nampa WWTP Emission Estimate Summary (boiler & flares scenario)

Preliminary Annual Emissions Estimates								
Criteria Pollutants[1]		Emission Rate (ton/year)						
Stack Name	Stack ID	PM	PM10	NOx	SO2	CO	VOC	Lead
Boiler 1 (NG & Biogas)	BOILER1	0.14	0.14	1.11	2.21	0.42	0.07	9.50E-06
Boiler 2 (NG & Biogas)	BOILER2	0.14	0.14	1.11	2.21	0.42	0.07	9.50E-06
Boiler 3 (NG & Biogas)	BOILER3	0.14	0.14	1.11	2.21	0.42	0.07	9.50E-06
Boiler 4 (NG & Biogas)	BOILER4	0.14	0.14	1.11	2.21	0.42	0.07	9.50E-06
Flare1	FLARE1	0.49	0.49	2.66	6.71	14.46	2.34	
Flare2	FLARE2	0.49	0.49	2.66	6.71	14.46	2.34	
Generator 1	GEN1	0.01	0.01	0.79	0.001	0.06	0.01	
Generator 2	GEN2	0.01	0.01	0.79	0.001	0.06	0.01	
Generator 3	GEN3	0.01	0.01	0.79	0.001	0.06	0.01	
VSB Heaters		0.03	0.03	0.34	0.002	0.29	0.02	1.72E-06
LTS Heaters		0.02	0.02	0.25	0.001	0.21	0.01	1.25E-06
LTS Hotsy	HOTSY	0.021	0.021	0.28	0.002	0.24	0.02	1.41E-06
Above Ground Storage Tank							5.59E-08	
Total		1.65	1.65	13.01	22.27	31.51	5.05	4.24E-05

Preliminary Maximum Hourly Emissions Estimates								
Criteria Pollutants[1]		Emission Rate (lb/hr)						
Stack Name	Stack ID	PM	PM10	NOx	SO2	CO	VOC	Lead
Boiler 1 (NG & Biogas)	BOILER1	0.03	0.03	0.25	0.50	0.10	0.02	2.17E-06
Boiler 2 (NG & Biogas)	BOILER2	0.03	0.03	0.25	0.50	0.10	0.02	2.17E-06
Boiler 3 (NG & Biogas)	BOILER3	0.03	0.03	0.25	0.50	0.10	0.02	2.17E-06
Boiler 4 (NG & Biogas)	BOILER4	0.03	0.03	0.25	0.50	0.10	0.02	2.17E-06
Flare1	FLARE1	0.11	0.11	0.61	1.53	3.30	0.54	
Flare2	FLARE2	0.11	0.11	0.61	1.53	3.30	0.54	
Generator 1	GEN1	0.12	0.12	15.89	0.01	1.15	0.14	
Generator 2	GEN2	0.12	0.12	15.89	0.01	1.15	0.14	
Generator 3	GEN3	0.12	0.12	15.89	0.01	1.15	0.14	
VSB Heaters		0.006	0.006	0.08	0.0005	0.07	0.004	3.92E-07
LTS Heaters		0.004	0.004	0.06	0.0003	0.05	0.003	2.84E-07
LTS Hotsy	HOTSY	0.005	0.005	0.064	0.0004	0.05	0.004	3.22E-07
Above Ground Storage Tank							1.12E-04	
Total		0.73	0.73	50.10	5.12	10.60	1.57	9.68E-06

Toxics[2] Toxic Air Pollutants	Boiler 1 (lb/hr)	Boiler 2 (lb/hr)	Boiler 3 (lb/hr)	Boiler 4 (lb/hr)	Flare(s) (lb/hr)	Gen 1 (lb/hr)	Gen 2 (lb/hr)	Gen 3 (lb/hr)	VSB Heaters (lb/hr)	LTS Heaters (lb/hr)	LTS Hotsy (lb/hr)	Total (lb/hr)	IDAPA 58.01.01.585 /586 - EL (lb/hr)	Exceeds Screening Level? (Y or N)
3-Methylchloranthrene	4.59E-09	4.59E-09	4.59E-09	4.59E-09					1.41E-09	1.02E-09	1.16E-09	2.20E-08	2.50E-06	No
Acetaldehyde						2.25E-06	2.25E-06	2.25E-06				6.75E-06	3.00E-03	No
Acrolein						1.54E-05	1.54E-05	1.54E-05				4.62E-05	1.70E-02	No
Ammonia	1.39E-02	1.39E-02	1.39E-02	1.39E-02	9.51E-02							1.51E-01	1.20E+00	No
Benzene	2.52E-05	2.52E-05	2.52E-05	2.52E-05	4.73E-03	6.93E-05	6.93E-05	6.93E-05	1.65E-06	1.19E-06	1.35E-06	5.04E-03	8.00E-04	Yes
Benzo(a)pyrene	3.06E-09	3.06E-09	3.06E-09	3.06E-09		2.30E-08	2.30E-08	2.30E-08	9.41E-10	6.82E-10	7.73E-10	8.35E-08	2.00E-06	No
Formaldehyde	1.91E-04	1.91E-04	1.91E-04	1.91E-04	3.48E-02	7.05E-06	7.05E-06	7.05E-06	5.88E-05	4.26E-05	4.83E-05	3.57E-02	5.10E-04	Yes
Hexane	4.59E-03	4.59E-03	4.59E-03	4.59E-03					1.41E-03	1.02E-03	1.16E-03	2.20E-02	1.20E+01	No
Hydrogen Sulfide	5.28E-03	5.28E-03	5.28E-03	5.28E-03	1.81E-01							2.02E-01	9.33E-01	No
Naphthalene	1.56E-06	1.56E-06	1.56E-06	1.56E-06		2.54E-04	2.54E-04	2.54E-04	4.78E-07	3.47E-07	3.93E-07	7.70E-04	3.33E+00	No
Pentane	6.64E-03	6.64E-03	6.64E-03	6.64E-03					2.04E-03	1.48E-03	1.67E-03	3.17E-02	1.18E+02	No
Toluene	8.68E-06	8.68E-06	8.68E-06	8.68E-06		5.50E-04	5.50E-04	5.50E-04	2.67E-06	1.93E-06	2.19E-06	1.69E-03	2.50E+01	No
Xylenes						3.78E-04	3.78E-04	3.78E-04				1.13E-03	2.90E+01	No
Total PAH[3]	1.74E-06	1.74E-06	1.74E-06	1.74E-06	4.16E-04	1.89E-05	1.89E-05	1.89E-05				4.80E-04	9.10E-05	Yes
Naphthalene (annual)	1.56E-06	1.56E-06	1.56E-06	1.56E-06		1.16E-05	1.16E-05	1.16E-05				4.11E-05	9.10E-05	No
POM (7-PAH)[4]	2.91E-08	2.91E-08	2.91E-08	2.91E-08					8.94E-09	6.48E-09	7.34E-09	1.39E-07	2.00E-06	No

Toxic Air Pollutants-Metals	Boiler 1 (lb/hr)	Boiler 2 (lb/hr)	Boiler 3 (lb/hr)	Boiler 4 (lb/hr)	Flare (lb/hr)	Gen 1 (lb/hr)	Gen 2 (lb/hr)	Gen 3 (lb/hr)	VSB Heaters (lb/hr)	LTS Heaters (lb/hr)	LTS Hotsy (lb/hr)	Total (lb/hr)	IDAPA 58.01.01.585 /586 - EL (lb/hr)	Exceeds Screening Level? (Y or N)
Arsenic	5.10E-07	5.10E-07	5.10E-07	5.10E-07	-	-	-	-	1.57E-07	1.14E-07	1.29E-07	2.31E-06	1.50E-06	Yes
Barium	1.12E-05	1.12E-05	1.12E-05	1.12E-05	-	-	-	-	3.45E-06	2.50E-06	2.83E-06	5.09E-05	3.30E-02	No
Beryllium	3.06E-08	3.06E-08	3.06E-08	3.06E-08	-	-	-	-	9.41E-09	6.82E-09	7.73E-09	1.39E-07	2.80E-05	No
Cadmium	2.81E-06	2.81E-06	2.81E-06	2.81E-06	-	-	-	-	8.63E-07	6.25E-07	7.09E-07	1.27E-05	3.70E-06	Yes
Chromium	3.57E-06	3.57E-06	3.57E-06	3.57E-06	-	-	-	-	1.10E-06	7.96E-07	9.02E-07	1.62E-05	3.30E-02	No
Cobalt	2.14E-07	2.14E-07	2.14E-07	2.14E-07	-	-	-	-	6.59E-08	4.78E-08	5.41E-08	9.71E-07	3.30E-03	No
Copper	2.17E-06	2.17E-06	2.17E-06	2.17E-06	-	-	-	-	6.67E-07	4.83E-07	5.48E-07	9.83E-06	1.30E-02	No
Manganese	9.70E-07	9.70E-07	9.70E-07	9.70E-07	-	-	-	-	2.98E-07	2.16E-07	2.45E-07	4.39E-06	6.70E-02	No
Mercury	6.64E-07	6.64E-07	6.64E-07	6.64E-07	-	-	-	-	2.04E-07	1.48E-07	1.67E-07	3.01E-06	1.00E-03	No
Molybdenum	2.81E-06	2.81E-06	2.81E-06	2.81E-06	-	-	-	-	8.63E-07	6.25E-07	7.09E-07	1.27E-05	3.33E-01	No
Nickel	5.36E-06	5.36E-06	5.36E-06	5.36E-06	-	-	-	-	1.65E-06	1.19E-06	1.35E-06	2.43E-05	2.75E-05	No
Selenium	6.12E-08	6.12E-08	6.12E-08	6.12E-08	-	-	-	-	1.88E-08	1.36E-08	1.55E-08	2.77E-07	1.30E-02	No
Vanadium	5.87E-06	5.87E-06	5.87E-06	5.87E-06	-	-	-	-	1.80E-06	1.31E-06	1.48E-06	2.66E-05	3.00E-03	No
Zinc	7.40E-05	7.40E-05	7.40E-05	7.40E-05	-	-	-	-	2.27E-05	1.65E-05	1.87E-05	3.35E-04	3.33E-01	No

Notes

[1]AP-42 emission factors were utilized to estimate emissions for particulate matter (PM), oxides of nitrogen (NOx), sulfur oxides (SOx), carbon monoxide (CO), and volatile organic compounds (VOCs).

[2] Toxic Air Pollutants (EPA AP-42, Section 1.4 and Section 3.4).

[3] Per IDEQ Total PAH is not modeled, only the maximum TAP of the PAH, which is Naphthalene as an annual 586, but the naphthalene emissions do not exceed the EL. Therefore, it was not modeled..

[4]Polycyclic Organic Matter is the sum of benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene.

Table 2. Nampa WWTP Hazardous Air Pollutant Summary (boiler & flares scenario)

HAP Pollutants	PTE (T/yr)
Acetaldehyde	2.96E-05
Acrolein	2.03E-04
Benzene	2.21E-02
Formaldehyde	1.56E-01
Hexane	9.62E-02
Hydrogen Sulfide	8.86E-01
Naphthalene	3.37E-03
Toluene	7.41E-03
Xylenes	4.96E-03
POM	6.09E-07
Arsenic	1.01E-05
Beryllium	6.08E-07
Cadmium (volatile metal)	5.57E-05
Chromium, total	7.09E-05
Cobalt	4.25E-06
Manganese	1.92E-05
Mercury (volatile metal)	1.32E-05
Nickel	1.06E-04
Selenium (volatile metal)	1.22E-06
Total HAPs	**1.18**

IDAPA 58.01.01.006 General Definitions
55. Hazardous Air Pollutant (HAP). Any air pollutant listed pursuant to Section 112(b) of the Clean Air Act. Hazardous Air Pollutants are regulated air pollutants.
https://www3.epa.gov/ttn/atw/188polls.html

Table 3. Nampa WWTP Toxic Air Pollutant Summary (boiler & flares scenario)

Non-Carcinogenic Toxic Air Pollutants (sum of all emissions)	Non-Carcinogenic Emissions (lb/hr)	IDAPA Screening Emission Level (lb/hr)	Exceeds Screening Level? (Yes/No)
Acrolein	4.62E-05	1.70E-02	No
Ammonia	1.51E-01	1.20E+00	No
Barium	5.09E-05	3.30E-02	No
Cobalt	9.71E-07	3.30E-03	No
Copper	9.83E-06	1.30E-02	No
Hexane	2.20E-02	1.20E+01	No
Hydrogen Sulfide	2.02E-01	9.33E-01	No
Manganese	4.39E-06	6.70E-02	No
Mercury	3.01E-06	1.00E-03	No
Molybdenum	1.27E-05	3.33E-01	No
Pentane	3.17E-02	1.18E+02	No
Selenium	2.77E-07	1.30E-02	No
Toluene	1.69E-03	2.50E+01	No
vanadium	2.66E-05	3.00E-03	No
Xylenes	1.13E-03	2.90E+01	No
Zinc	3.35E-04	3.33E-01	No

Carcinogenic Toxic Air Pollutants (sum of all emissions)	Carcinogenic Emissions (lb/hr)	IDAPA Screening Emission Level (lb/hr)	Exceeds Screening Level? (Yes/No)
3-Methylchloanthrene	2.20E-08	2.50E-06	No
Acetaldehyde	6.75E-06	3.00E-03	No
Arsenic	**2.31E-06**	1.50E-06	Yes
Benzene	**5.04E-03**	8.00E-04	Yes
Benzo(a)pyrene	8.35E-08	2.00E-06	No
Beryllium	1.39E-07	2.80E-05	No
Cadmium	**1.27E-05**	3.70E-06	Yes
Chromium	1.62E-05	3.30E-02	No
Formaldehyde	**3.57E-02**	5.10E-04	Yes
Napthalene	7.70E-04	3.33E+00	No
Nickel	2.43E-05	2.75E-05	No
Napthalene (annual)	4.11E-05	9.10E-05	No
POM	1.39E-07	2.00E-06	No

Table 1. Nampa WWTP Emission Estimate Summary (flares only scenario)

Preliminary Annual Emissions Estimates

Criteria Pollutants[1]		Emission Rate (ton/year)						
Stack Name	Stack ID	PM	PM10	NOx	SO2	CO	VOC	Lead
Boiler 1 (NG & Biogas)	BOILER1	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Boiler 2 (NG & Biogas)	BOILER2	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Boiler 3 (NG & Biogas)	BOILER3	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Boiler 4 (NG & Biogas)	BOILER4	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Flare1	FLARE1	0.78	0.78	4.21	10.62	22.89	3.71	
Flare2	FLARE2	0.78	0.78	4.21	10.62	22.89	3.71	
Generator 1	GEN1	0.01	0.01	0.79	0.001	0.06	0.01	
Generator 2	GEN2	0.01	0.01	0.79	0.001	0.06	0.01	
Generator 3	GEN3	0.01	0.01	0.79	0.001	0.06	0.01	
VSB Heaters		0.03	0.03	0.34	0.002	0.29	0.02	1.72E-06
LTS Heaters		0.02	0.02	0.25	0.001	0.21	0.01	1.25E-06
LTS Hotsy	HOTSY	0.021	0.021	0.28	0.002	0.24	0.02	1.41E-06
Above Ground Storage Tank							5.59E-08	
Total		1.65	1.65	11.67	21.25	46.69	7.49	4.37E-06

Preliminary Maximum Hourly Emissions Estimates

Criteria Pollutants[1]		Emission Rate (lb/hr)						
Stack Name	Stack ID	PM	PM10	NOx	SO2	CO	VOC	Lead
Boiler 1 (NG & Biogas)	BOILER1	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Boiler 2 (NG & Biogas)	BOILER2	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Boiler 3 (NG & Biogas)	BOILER3	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Boiler 4 (NG & Biogas)	BOILER4	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00
Flare1	FLARE1	0.18	0.18	0.96	2.43	5.23	0.85	
Flare2	FLARE2	0.18	0.18	0.96	2.43	5.23	0.85	
Generator 1	GEN1	0.12	0.12	15.89	0.01	1.15	0.14	
Generator 2	GEN2	0.12	0.12	15.89	0.01	1.15	0.14	
Generator 3	GEN3	0.12	0.12	15.89	0.01	1.15	0.14	
VSB Heaters		0.006	0.006	0.08	0.0005	0.07	0.004	3.92E-07
LTS Heaters		0.004	0.004	0.06	0.0003	0.05	0.003	2.84E-07
LTS Hotsy	HOTSY	0.005	0.005	0.064	0.0004	0.05	0.004	3.22E-07
Above Ground Storage Tank							1.12E-04	
Total		0.73	0.73	49.79	4.89	14.07	2.13	9.99E-07

Toxics[2] Toxic Air Pollutants	Boiler 1 (lb/hr)	Boiler 2 (lb/hr)	Boiler 3 (lb/hr)	Boiler 4 (lb/hr)	Flare(s) (lb/hr)	Gen 1 (lb/hr)	Gen 2 (lb/hr)	Gen 3 (lb/hr)	VSB Heaters (lb/hr)	LTS Heaters (lb/hr)	LTS Hotsy (lb/hr)	Total (lb/hr)	IDAPA 58.01.01.585 /586 - EL (lb/hr)	Exceeds Screening Level? (Y or N)
3-Methylchloranthrene	0.00E+00	0.00E+00	0.00E+00	0.00E+00					1.41E-09	1.02E-09	1.16E-09	3.59E-09	2.50E-06	No
Acetaldehyde						2.25E-06	2.25E-06	2.25E-06				6.75E-06	3.00E-03	No
Acrolein						1.54E-05	1.54E-05	1.54E-05				4.62E-05	1.70E-02	No
Ammonia	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.51E-01							1.51E-01	1.20E+00	No
Benzene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.49E-03	6.93E-05	6.93E-05	6.93E-05	1.65E-06	1.19E-06	1.35E-06	7.70E-03	8.00E-04	**Yes**
Benzo(a)pyrene	0.00E+00	0.00E+00	0.00E+00	0.00E+00		2.30E-08	2.30E-08	2.30E-08	9.41E-10	6.82E-10	7.73E-10	7.13E-08	2.00E-06	No
Formaldehyde	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.50E-02	7.05E-06	7.05E-06	7.05E-06	5.88E-05	4.26E-05	4.83E-05	5.52E-02	5.10E-04	**Yes**
Hexane	0.00E+00	0.00E+00	0.00E+00	0.00E+00					1.41E-03	1.02E-03	1.16E-03	3.59E-03	1.20E+01	No
Hydrogen Sulfide	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.87E-01							2.87E-01	9.33E-01	No
Naphthalene	0.00E+00	0.00E+00	0.00E+00	0.00E+00		2.54E-04	2.54E-04	2.54E-04	4.78E-07	3.47E-07	3.93E-07	7.64E-04	3.33E+00	No
Pentane	0.00E+00	0.00E+00	0.00E+00	0.00E+00					2.04E-03	1.48E-03	1.67E-03	5.19E-03	1.18E+02	No
Toluene	0.00E+00	0.00E+00	0.00E+00	0.00E+00		5.50E-04	5.50E-04	5.50E-04	2.67E-06	1.93E-06	2.19E-06	1.66E-03	2.50E+01	No
Xylenes						3.78E-04	3.78E-04	3.78E-04				1.13E-03	2.90E+01	No
Total PAH[3]	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.59E-04	1.89E-05	1.89E-05	1.89E-05				7.16E-04	9.10E-05	**Yes**
Naphthalene (annual)	0.00E+00	0.00E+00	0.00E+00	0.00E+00		1.16E-05	1.16E-05	1.16E-05				3.48E-05	9.10E-05	No
POM (7-PAH)[4]	0.00E+00	0.00E+00	0.00E+00	0.00E+00					8.94E-09	6.48E-09	7.34E-09	2.28E-08	2.00E-06	No

Toxic Air Pollutants-Metals	Boiler 1 (lb/hr)	Boiler 2 (lb/hr)	Boiler 3 (lb/hr)	Boiler 4 (lb/hr)	Flare (lb/hr)	Gen 1 (lb/hr)	Gen 2 (lb/hr)	Gen 3 (lb/hr)	VSB Heaters (lb/hr)	LTS Heaters (lb/hr)	LTS Hotsy (lb/hr)	Total (lb/hr)	IDAPA 58.01.01.585 /586 - EL (lb/hr)	Exceeds Screening Level? (Y or N)
Arsenic	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	1.57E-07	1.14E-07	1.29E-07	2.71E-07	1.50E-06	**No**
Barium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	3.45E-06	2.50E-06	2.83E-06	5.95E-06	3.30E-02	No
Beryllium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	9.41E-09	6.82E-09	7.73E-09	1.62E-08	2.80E-05	No
Cadmium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	8.63E-07	6.25E-07	7.09E-07	1.49E-06	3.70E-06	**No**
Chromium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	1.10E-06	7.96E-07	9.02E-07	1.89E-06	3.30E-02	No
Cobalt	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	6.59E-08	4.78E-08	5.41E-08	1.14E-07	3.30E-03	No
Copper	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	6.67E-07	4.83E-07	5.48E-07	1.15E-06	1.30E-02	No
Manganese	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	2.98E-07	2.16E-07	2.45E-07	5.14E-07	6.70E-02	No
Mercury	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	2.04E-07	1.48E-07	1.67E-07	3.52E-07	1.00E-03	No
Molybdenum	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	8.63E-07	6.25E-07	7.09E-07	1.49E-06	3.33E-01	No
Nickel	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	1.65E-06	1.19E-06	1.35E-06	2.84E-06	2.75E-05	No
Selenium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	1.88E-08	1.36E-08	1.55E-08	3.25E-08	1.30E-02	No
Vanadium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	1.80E-06	1.31E-06	1.48E-06	3.11E-06	3.00E-03	No
Zinc	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	-	-	2.27E-05	1.65E-05	1.87E-05	3.92E-05	3.33E-01	No

Notes

[1] AP-42 emission factors were utilized to estimate emissions for particulate matter (PM), oxides of nitrogen (NOx), sulfur oxides (SOx), carbon monoxide (CO), and volatile organic compounds (VOCs).

[2] Toxic Air Pollutants (EPA AP-42, Section 1.4 and Section 3.4).

[3] Per IDEQ Total PAH is not modeled, only the maximum TAP of the PAH, which is Naphthalene as an annual 586, but the naphthalene emissions do not exceed the EL. Therefore, it was not modeled..

[4] Polycyclic Organic Matter is the sum of benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene.

Table 2. Nampa WWTP Hazardous Air Pollutant Summary (flares only scenario)

HAP Pollutants	PTE (T/yr)
Acetaldehyde	2.96E-05
Acrolein	2.03E-04
Benzene	3.37E-02
Formaldehyde	2.42E-01
Hexane	1.57E-02
Hydrogen Sulfide	1.26E+00
Naphthalene	3.35E-03
Toluene	7.25E-03
Xylenes	4.96E-03
POM	9.97E-08
Arsenic	1.19E-06
Beryllium	7.11E-08
Cadmium (volatile metal)	6.52E-06
Chromium, total	8.30E-06
Cobalt	4.98E-07
Manganese	2.25E-06
Mercury (volatile metal)	1.54E-06
Nickel	1.24E-05
Selenium (volatile metal)	1.42E-07
Total HAPs	**1.56**

IDAPA 58.01.01.006 General Definitions
55. Hazardous Air Pollutant (HAP). Any air pollutant listed pursuant to Section 112(b) of the Clean Air Act. Hazardous Air Pollutants are regulated air pollutants.
https://www3.epa.gov/ttn/atw/188polls.html

Table 3. Nampa WWTP Toxic Air Pollutant Summary (flares only scenario)

Non-Carcinogenic Toxic Air Pollutants (sum of all emissions)	Non-Carcinogenic Emissions (lb/hr)	IDAPA Screening Emission Level (lb/hr)	Exceeds Screening Level? (Yes/No)
Acrolein	4.62E-05	1.70E-02	No
Ammonia	1.51E-01	1.20E+00	No
Barium	5.95E-06	3.30E-02	No
Cobalt	1.14E-07	3.30E-03	No
Copper	1.15E-06	1.30E-02	No
Hexane	3.59E-03	1.20E+01	No
Hydrogen Sulfide	2.87E-01	9.33E-01	No
Manganese	5.14E-07	6.70E-02	No
Mercury	3.52E-07	1.00E-03	No
Molybdenum	1.49E-06	3.33E-01	No
Pentane	5.19E-03	1.18E+02	No
Selenium	3.25E-08	1.30E-02	No
Toluene	1.66E-03	2.50E+01	No
vanadium	3.11E-06	3.00E-03	No
Xylenes	1.13E-03	2.90E+01	No
Zinc	3.92E-05	3.33E-01	No

Carcinogenic Toxic Air Pollutants (sum of all emissions)	Carcinogenic Emissions (lb/hr)	IDAPA Screening Emission Level (lb/hr)	Exceeds Screening Level? (Yes/No)
3-Methylchloanthrene	3.59E-09	2.50E-06	No
Acetaldehyde	6.75E-06	3.00E-03	No
Arsenic	**2.71E-07**	1.50E-06	No
Benzene	**7.70E-03**	8.00E-04	Yes
Benzo(a)pyrene	7.13E-08	2.00E-06	No
Beryllium	1.62E-08	2.80E-05	No
Cadmium	**1.49E-06**	3.70E-06	No
Chromium	1.89E-06	3.30E-02	No
Formaldehyde	**5.52E-02**	5.10E-04	Yes
Napthalene	7.64E-04	3.33E+00	No
Nickel	2.84E-06	2.75E-05	No
Napthalene (annual)	3.48E-05	9.10E-05	No
POM	2.28E-08	2.00E-06	No

APPENDIX B – AMBIENT AIR IMPACT ANALYSES

MEMORANDUM

DATE: October 18, 2019

TO: Morrie Lewis, Permit Writer, Air Program

FROM: Darrin Mehr, Dispersion Modeling Analyst, Air Program

PROJECT: P-2010.0182 PROJ 62235 – Permit to Construct (PTC) Modification Application for the City of Nampa Wastewater Treatment Plant for the Expansion of the Existing Facility in Nampa, Idaho

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs)

Contents

Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a Non-Carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
ACFM	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
ARM	Ambient Ratio Method
bhp	Brake horsepower
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
Btu/hr	British Thermal Units per hour
CAPCOA	California Air Pollution Control Officers Association
CFR	Code of Federal Regulations
City of Nampa	City of Nampa (permit applicant and operator of the wastewater treatment plant)
cfm	Cubic Feet per Minute
CMAQ	Community Multi-Scale Air Quality Modeling System
CO	Carbon Monoxide
DEQ	Idaho Department of Environmental Quality
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
fps	Feet per second
GEP	Good Engineering Practice
hr	Hours
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
ISR	In-Stack Ratio
K	Kelvin
kW	Kilowatts
m	Meters
MACT	Maximum Achievable Control Technology
m/s	Meters per second
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Dataset
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NEI	National Emissions Inventory
NESHAP	National Emission Standard for Hazardous Air Pollutants
NSPS	New Source Performance Standard
NWS	National Weather Service
NW AIRQUEST	Northwest International Air Quality Environmental Science and Technology Consortium
O_3	Ozone

OLM	Ozone Limiting Method
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	Parts Per Billion
ppm_v	Parts per Million Based on Volume
PRIME	Plume Rise Model Enhancement
PTC	Permit to Construct
PTE	Potential to Emit
PVMRM	Plume Volume Molar Ratio Method
scf	Standard Cubic Feet
scf/day	Standard Cubic Feet per Day
SCREEN3	Screening Procedures for Estimating the Air Quality Impact of Stationary Sources
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
Stantec	Stantec Consultants (applicant's permitting and modeling consultant)
T2 ARM2	Tier 2 Ambient Ratio Method 2
TAP	Toxic Air Pollutant
tons/year	Ton(s) per year
ULSD	Ultra Low Sulfur Diesel
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOCs	Volatile Organic Compounds
WWTP	Wastewater Treatment Plant
°F	Degrees Fahrenheit
$\mu g/m^3$	Micrograms per cubic meter of air

1.0 Summary

1.1 General Project Summary

On May 19, 2019, the City of Nampa submitted an application for a Permit to Construct (PTC) for a modification to the existing Wastewater Treatment Plant (WWTP) facility located at 340 West Railroad Street, in Nampa, Idaho.

Project-specific air quality impact analyses involving atmospheric dispersion modeling of estimated emissions associated with the entire facility were submitted to DEQ to demonstrate that the proposed modification would not cause or significantly contribute to a violation of any ambient air quality standard as required by IDAPA 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03). Stantec Consulting (Stantec), the City of Nampa's permitting and modeling consultant, submitted analyses and applicable information and data to enable DEQ to evaluate potential impacts to ambient air.

Stantec performed project-specific air quality impact analyses to demonstrate compliance with air quality standards for the proposed project, consisting of a proposed expansion of the facility and changes to current permit conditions for the existing facility. The facility currently operates under PTC P-2010.0182 PROJECT 62111, issued October 19, 2018. The permitting project and modeling demonstration includes the changes planned for the Phase II expansion project, which includes:

- Construction of a fifth primary anaerobic digester (primary digester producing biogas) and a second candlestick flare to be placed immediately next to the relocated existing flare.
- An increase in the biogas allowed to be produced at the facility and combusted in the facility's boilers and candlestick flares, changing the current facility-wide permitted limit of 1,050,000 standard cubic feet per day (scf/day) to a limitation of 1,130,088 scf/day.
- Reduction in the allowable hydrogen sulfide (H_2S) concentration in the combusted biogas from 1,200 parts per million by volume (ppm_v) to a final permit limitation of 700 ppm_v, as controlled by chemical addition to the anaerobic digester process.
- Removal of the de-rated heat input capacity for Boiler 1, which is currently limited to 2.25 MMBtu/hr heat input capacity to the manufacturer's rated heat input capacity of 2.6 MMBtu/hr.
- Revision of combustion emission factors based on Caterpillar manufacturer's data for the three existing diesel-fired emergency electricity generating engines, resulting in reductions in emission rates estimates. Emissions estimates for some pollutants were also altered based on data from Folsom Industrial, the boiler vendor, for the four existing Burnham boilers.
- Reduction of the annual operating hours of the three existing diesel-fired emergency electricity generator engines from 500 hours per year to 100 hours per year to match the NSPS Subpart IIII limitation for emergency engines.

The DEQ review of the air impact analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the pollutant dispersion modeling analyses used to demonstrate that the estimated emissions associated with operation of the facility, as modified, will not cause or significantly contribute to a violation of the applicable air quality standards. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. This modeling review also did not evaluate the accuracy of emissions estimates. Evaluation of emissions estimates was the responsibility of the permit writer and is addressed in the main body of the DEQ Statement of Basis.

The submitted air quality impact analyses: 1) utilized appropriate methods and models according to established DEQ/EPA rules, policies, guidance, and procedures; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that predicted pollutant concentrations from emissions associated with the facility as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or b) that predicted pollutant concentrations from applicable emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable National Ambient Air Quality Standards (NAAQS) at ambient air locations where and when the project has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emissions increases associated with the project do not result in increased emissions and modeling was not required to demonstrate compliance with any TAPs increments. Table 1 presents key assumptions and results to be considered in the development of the permit.

Table 1. KEY CONDITIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
General Emission Rates. Emission rates used in the air impact analyses, as listed in this memorandum, must represent maximum potential emissions as given by design capacity, inherently limited by the nature of the process or configuration of the facility, or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emission rates greater than those used in the air impact analyses.
Air Impact Analyses for Criteria Pollutant Emissions. Facility-wide PTE and the requested permit limitation changes for annual and 24-hour $PM_{2.5}$[a], 24-hour PM_{10}[b], 1-hour and annual NO_2[c], 1-hr, 3-hr, 24-hr and annual SO_2[d], and Pb[e] does not qualify them for a BRC exemption. Moreover, their short- and long-term emissions are greater than DEQ Level I modeling thresholds, except for 1-hour and 8-hour CO[f], and monthly lead. Therefore, these pollutants and averaging times are subject to NAAQS Compliance Demonstration requirements. CO emissions were exempted from modeling requirements but the applicant conducted analyses for 1-hour and 8-hour CO NAAQS.	Project-specific air impact analyses demonstrating compliance with NAAQS, as required by Idaho Air Rules Section 203.02, are required for pollutant increases above BRC thresholds, or for pollutants having an emissions increase that is greater than Level I modeling applicability thresholds (where the BRC exclusion cannot be used).
Air Impact Analyses for TAP Emissions. Facility-wide emissions of TAPs were evaluated for increment compliance, and TAPs other than arsenic, benzene, cadmium, and formaldehyde were below ELs. Analyses demonstrating compliance with arsenic, benzene, cadmium, and formaldehyde TAP increments were performed.	A TAP increment compliance demonstration would be required for any TAPs with emissions above ELs. This project analyzed TAPs emissions applicability using baseline emission rates of 0.0 lb/hr and 0.0 T/yr.
Boilers 1, 2, 3, 4 (model IDs BOILER1, BOILER2, BOILER3, and BOILER4) Dual fuel-fired on either biogas as the primary fuel and natural gas as a backup fuel. Hours of operation on the worst case fuel—biogas—were modeled as unlimited at the rated heat input capacities of 2.60 MMBtu/hr for each boiler. Boilers are not anticipated to operate at partial load capacity. Boilers were described as operating at 100% load or 0% load only. Any amount of biogas generated that is below 100% load for a boiler is flared. DEQ conducted a sensitivity analysis based on 75% load SO_2 emission rates and boiler vendor-	Each of the boilers operates at 100% load or is idled with zero emissions. The requested operating condition where each boiler operates either at 100% load or 0% load while combusting biogas is supported. It is critical for SO_2 NAAQS compliance that boilers not operate at intermediate loads. This concern does not affect operation firing natural gas because natural gas produces minimal SO_2 emissions.

Table 1. KEY CONDITIONS USED IN MODELING ANALYSES	
supplied 75% load release parameters, which resulted in an impact slightly exceeding the 1-hour SO_2 NAAQS.	
Candlestick Flares 1 and 2 (FLARE1 and FLARE2) Candlestick flares, also referred to as "open" flares, were modeled for two scenarios: 1) unlimited operation at maximum biogas generation capacity, where all biogas generated is combusted in the four existing boilers (at each emission unit's rated capacity)and the rest of the allowable biogas combusted in the one existing candlestick flare and one new candlestick flare; 2) the entire quantity of allowable biogas combusted in the two candlestick flares.	Worst-case flaring of up to 1,130,088 scf/day (47,087 scf/hr) and 412.48 MMscf/year of biogas was modeled and demonstrated compliance with all NAAQS and TAPs increments. This represents unrestricted incineration of permit-allowable biogas generated on-site with a heat input content of 600 Btu/scf and 700 ppm_v of H_2S.
Diesel-fired Emergency Electricity Generator Engines (GEN1, GEN2, GEN3) Each generator engine was modeled with SO_2 emissions based on ULSD fuel, limiting SO_2 emissions. Each generator engine was modeled for 6 hours per day and 100 hours per year. Specific time-of-day assumptions were not applied and the emergency generator engines may operate at any time of the day.	The number of hours per day modeled was unchanged from the current permitted hours. Annual operating hours were reduced to reflect current assumptions for emergency engines. Each engine is allowed to operate for maintenance and testing purposes at any time of the day, on any day of the year, for up to 6 hours per day on any schedule during the day and up to 100 hours per year.
Heaters (model IDs VSBHEAT1, VBSHEAT2, VBSHEAT3, VBSHEAT4, LTSHEAT1, LTSHEAT2, LTSHEAT3, LTSHEAT4, and LTSHOTSY) These emissions units are fired exclusively on natural gas for unlimited daily and annual hours.	These emissions units are fired on natural gas. Biogas is not combusted in these emissions units. These units were modeled without capacity or operating schedule limitations.
Biogas Hydrogen sulfide (H_2S) Limitation and Heat Content Modeled SO_2 emission rates reflected a 700 ppm_v limitation. The existing permit limitation is 1,200 ppm_v. This limitation affects all four boilers and the two candlestick flares. This project uses on-site-generated anaerobic digester biogas heat content of 600 Btu/scf. Past projects applied heat contents of 700 Btu/scf for certain sources.	SO_2 emissions vary directly with the H_2S content of the biogas generated on-site. 1-hour SO_2 NAAQS compliance was demonstrated by a very small margin for the normal operations scenario, with the majority of the design impact attributed to the four Burnham boilers. Compliance would not be demonstrated for SO_2 emission rates based on H_2S content in biogas exceeding 700 ppm_v. Emissions estimates are generally dependent upon quantities of biogas combusted in terms of scf/hour, scf/day, and scf/year. Heat content, in terms of Btu/scf, are used with emission factors in terms of Btu/scf combusted to estimate emissions.
Removal of Existing Raincaps Boilers 1, 2, 3, and 4 were modeled with uninterrupted vertical release points. All four boiler stacks are currently equipped with rain caps as represented in past ambient impact analyses for this facility. Existing stack release heights and exit diameters were not altered. All VBS and LTS heater stacks and the LTS pressure washer stacks are to remain equipped with rain caps.	The permit should contain a permit condition requiring each boiler stack to be altered to have an uninterrupted vertical release upon permit issuance with removal of the existing rain caps. This only affects the four existing boilers.
Boiler 1 (BOILER1) Removal of De-Rating of Heat Input Capacity Boiler 1 was limited to 2.25 MMBtu/hr heat input capacity. This project reflected a heat input capacity of 2.60 MMBtu/hr for both biogas and natural gas.	Boiler 1 emissions and impacts reflected full rated capacity for this emissions unit.

[a] Particulate matter with a mean aerodynamic diameter of 2.5 microns or less.
[b] Particulate matter with a mean aerodynamic diameter of 10 microns or less.
[c] Nitrogen dioxide.

d. Sulfur dioxide.
e. Lead.
f. Carbon monoxide.

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department, using DEQ/EPA established guidance, policies, and procedures, that operation of the proposed facility or modification will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

1.2 Summary of Submittals and Actions

April 5, 2019:	Representatives of the City of Nampa, Stantec, and DEQ participated in a PTC pre-application meeting at DEQ's State Office.
April 8, 2019:	DEQ sent Stantec the current Boise airport meteorological dataset for the modeling analyses via email.
April 19, 2019:	Stantec submitted a modeling protocol, on behalf of the City of Nampa, to DEQ via email.
May 10, 2019:	DEQ issued a conditional modeling protocol for the project via email.
May 14, 2019:	DEQ received a PTC modification application from Stantec, submitted on behalf of the City of Nampa.
June 10, 2019:	The application was declared incomplete.
June 19, 2019:	DEQ received a submittal responding to the incompleteness determination.
July 17, 2019:	The application was declared incomplete.
August 7, 2019:	Representatives for DEQ, Stantec, and the City of Nampa participated in a meeting to discuss issues related to the applicant's response to the incompleteness determination.
August 15, 2019:	Stantec, on behalf of the City of Nampa, submitted a response to the July 17, 2019, incompleteness determination via an ftp site.
August 30, 2019:	DEQ declared the permit application complete.

2.0 Background Information

2.1 Permit Requirements for Permits to Construct

PTCs are issued to authorize the construction of a new source or modification of an existing source or permit. Idaho Air Rules Section 203.02 requires that emissions from the new source or modification not cause or significantly contribute to a violation of an air quality standard, and Idaho Air Rules Section 203.03 requires that emissions from a new source or modification comply with applicable toxic air pollutant (TAP) increments of Idaho Air Rules Sections 585 and 586.

2.2 Project Location and Area Classification

The facility is located in Nampa, Idaho, in Canyon County. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$).

2.3 Modeling Applicability for Criteria Pollutants

2.3.1 Below Regulatory Concern and DEQ Modeling Guideline Level I and II Thresholds

Idaho Air Rules Section 203.02 state that a PTC cannot be issued unless the application demonstrates to the satisfaction of DEQ that the new source or modification will not cause or significantly contribute to a NAAQS violation. Atmospheric dispersion modeling is used to evaluate the potential impact of a proposed project to ambient air and demonstrate NAAQS compliance. However, if the emissions associated with a project are very small, project-specific modeling analyses may not be necessary.

If project-wide potential to emit (PTE) values for criteria pollutants would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of one or more criteria pollutants exceeding the BRC threshold of 10% of emissions defined by Idaho Air Rules as significant, then an air impact analysis may not be required for those pollutants. DEQ's regulatory interpretation policy[1] of exemption provisions of Idaho Air Rules Section 221 is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant." The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year. This permitting project cannot qualify for a BRC exemption from Idaho Air Rules Section 203.02 because there are existing permit conditions that require changes.

Site-specific air impact analyses may not be required for a project, even when the project cannot use the BRC exemption from the NAAQS demonstration requirements. If the emissions increases associated with a project are below modeling applicability thresholds established in the *Idaho Air Modeling Guideline* ("State of Idaho Guideline for Performing Air Quality Impact Analyses[2]," available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf), then a project-specific analysis is not required. Modeling applicability emissions thresholds were developed by DEQ based on modeling of a hypothetical source and were designed to reasonably ensure that impacts are below the applicable SIL. DEQ has established two threshold levels: Level 1 thresholds are unconditional thresholds, requiring no DEQ approval for use; Level 2 thresholds are conditional upon DEQ approval, which depends on evaluation of the project and the site, including emissions quantities, stack parameters, number of sources emissions are distributed amongst, distance between the sources and the ambient air boundary, and the presence of sensitive receptors near the ambient air boundary. DEQ determined that Level 1 modeling thresholds are appropriate for this project and Level 2 thresholds were not approved by DEQ, in part due to potential building downwash issues for some sources.

The City of Nampa was issued PTC P-2010.0182, Project 6211, which de-rated existing Boiler 1 from 2.60 MMBtu/hr to 2.25 MMBtu/hr heat input capacity and added a fourth primary anaerobic digester. This project will add a fifth primary anaerobic digester, increase allowable biogas generation capacity and allowable biogas throughput to the facility's four existing boilers, relocate existing candlestick flare, add a proposed new candlestick flare, and increase biogas throughput to the flares. Existing permit conditions will be modified to accommodate the requested changes, thus BRC modeling exemptions are not applicable for this project. Stantec and the City of Nampa proposed to perform dispersion modeling analyses for all pollutants. DEQ evaluated applicability based on Level 1 modeling thresholds of the DEQ *Modeling Guideline*[2] by comparing facility-wide future allowable emissions to the thresholds. DEQ found CO emissions were below the Level 1 modeling threshold and indicated that the project's CO emissions were exempt from modeling in the modeling protocol. Stantec performed modeling for 1-hour and 8-hour CO NAAQS at their discretion.

Lead emissions were included presented in the project's emissions inventory. Lead emissions were below the Level 1 modeling threshold and were not required to be modeled. Stantec and the City of Nampa did not model lead emissions.

As shown below in Table 2, the project's emissions increases of PM_{10}, $PM_{2.5}$, SO_2, and NO_x exceeded the Level 1 Modeling Applicability Thresholds, and a site-specific impact analysis was required for these pollutants. Impact analyses were not required for CO and lead emissions because facility-wide emissions were below Level 1 modeling thresholds.

Table 2. SITE-SPECIFIC CRITERIA POLLUTANT MODELING APPLICABILITY

Pollutant	Averaging Period	Emissions	Modeling Thresholds[a]		Site-Specific Modeling Required?
			Level I	Level II	
PM_{10}[b]	24-hour	Normal Operations – 0.73 lb/hr Maximum Flaring - 0.73 lb/hr	0.22	2.6	Yes
$PM_{2.5}$[c]	24-hour	Normal Operations – 0.73 lb/hr Maximum Flaring – 0.73 lb/hr	0.054	0.63	Yes
	Annual	Normal Operations – 0.73 lb/hr Maximum Flaring – 1.65 ton/yr	0.35	4.1	Yes
Carbon Monoxide (CO)	1-hour, 8-hour	Normal Operations – 10.6 lb/hr Maximum Flaring – 14.1 lb/hr	15	175	No
Sulfur Dioxide (SO_2)	1-hour, 3-hour, 24-hour	Normal Operations – 5.1 lb/hr Maximum Flaring – 4.9 lb/hr	0.21	2.5	Yes
	Annual	Normal Operations – 22.3 ton/yr Maximum Flaring – 21.3 ton/yr	1.2	14	Yes
Nitrogen Oxides (NOx)	1-hour	Normal Operations – 50.1 lb/hr[e] Maximum Flaring – 49.8 lb/hr[e]	0.20	2.4	Yes

	Annual	Normal Operations – 13.0 ton/yr	1.2	14	Yes
		Maximum Flaring – 11.7 ton/yr			
Lead (Pb)	monthly	Normal Operations – 7.1E-03 lb/month	14		No
		Maximum Flaring – 7.3E-04 lb/month			

[a] Level II Modeling Thresholds were not approved by DEQ for this project.
[b] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
[c] Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

2.3.2 Ozone Modeling Applicability

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NO_x, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Addressing secondary formation of O_3 has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

The allowable emissions increase of 1.3 tons/year VOCs for the normal operating scenario is well below the 100 tons/year threshold. This project will reduce allowable NOx emissions by 16.7 tons/year. On a facility-wide post-project potential to emit basis, VOCs emissions will be limited to 5.1 tons/year and NOx emissions will be limited to 13.0 tons/year for normal operations.

A worst-case flaring scenario was also identified and evaluated for 8,760 hours per year, which is not anticipated to occur. This worst-case flaring approach resulted in an increase in potential emissions of VOCs of 3.7 tons/year, for a PTE of 7.5 tons/year, and a decrease in potential emissions of NOx of 18.0 tons/year, for a PTE of 11.7 tons/year. DEQ determined it was not appropriate or necessary to require a quantitative source-specific O_3 impact analysis.

Requested allowable facility-wide criteria pollutant emissions were below annual significant emission rate thresholds. Secondary formation of ozone on an 8-hour basis was not required to be evaluated for ozone formation from VOCs and NOx emissions.

2.3.3 Secondary Particulate Formation Modeling Applicability

Under the normal operating scenario, accounting for all boilers operating on biogas at rated capacity and the rest of the allowable biogas production being flared, this project will decrease allowable NO_x emissions by 16.7 tons/year to a facility-wide emission rate of 13.0 tons/year, and SO_2 emissions will decrease by 18.2 tons/year to a facility-wide emission rate of 22.3 tons/year.

This project also analyzed a worst-case scenario that is not intended to occur with all biogas being incinerated in the two flares and all four boilers idled for 8,760 hours per year. Potential emissions under this maximized flaring scenario allowable NO_x emissions were estimated to decrease by 18.0 tons/year to 11.7 tons/year post-project PTE, and allowable SO_2 emissions were estimated to decrease by 19.2 tons/year to 21.3 tons/year.

The impact from secondary particulate formation resulting from emissions of NOx and SO_2 was assumed by DEQ to be negligible on the basis of the magnitude of emissions and the short distance from emissions sources to modeled receptors where maximum PM_{10} and $PM_{2.5}$ impacts would be anticipated. Requested allowable facility-wide criteria pollutant emissions were below annual significant emission rate thresholds and the project reduced allowable emissions of SO_2 and NOx. Secondary formation of 24-hour and annual $PM_{2.5}$ was not required to be evaluated for particulate formation from SO_2 and NO_x emissions.

2.4 Significant and Cumulative NAAQS Impact Analyses

If maximum modeled pollutant impacts to ambient air from emissions sources associated with a new facility or the emissions increase associated with a modification exceed the SILs of Idaho Air Rules Section 006 (referred to as a significant contribution in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02. A cumulative NAAQS impact analysis may also be required for permit revisions driven by compliance/enforcement actions, any correction of emissions limits or other operational parameters that may affect pollutant impacts to ambient air, or other cases where DEQ believes NAAQS may be threatened by the emissions associated with the facility or proposed project.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts, according to established DEQ/EPA guidance, policies, and procedures, from applicable facility-wide emissions and emissions from any nearby co-contributing sources. A DEQ-approved background concentration value is then added to the modeled result that is appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 3. Table 3 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis.

Table 3. APPLICABLE REGULATORY LIMITS				
Pollutant	**Averaging Period**	**Significant Impact Levels[a] (μg/m³)[b]**	**Regulatory Limit[c] (μg/m³)**	**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	0.2	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 μg/m³)	75 ppb[p] (196 μg/m³)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 μg/m³)	100 ppb[s] (188 μg/m³)	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]	70 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 per 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.

If the cumulative NAAQS impact analysis predicts a violation of the standard, the permit cannot be issued if the proposed project or facility has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. The facility or project does not have a significant contribution to a violation if impacts are below the SIL at all specific receptors showing violations during the time periods when modeled violations occurred.

Compliance with Idaho Air Rules Section 203.02 is demonstrated if: a) specific applicable criteria pollutant emissions increases are at a level defined as Below Regulatory Concern (BRC), using the criteria established by DEQ regulatory interpretation[1], or alternatively, if BRC is not applicable, pollutant emissions increases are at a level below the Level 1 de minimis modeling threshold or the

DEQ-approved Level 2 modeling threshold in the DEQ *Modeling Guideline*[2]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the cumulative NAAQS impact analysis (modeling applicable emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60 (NSPS), 61 (NESHAP), or 63 (MACT), then a TAP impact analysis under Section 210 is not required for that TAP. The DEQ permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion. Facility-wide TAPs were modeled by Stantec and the City of Nampa reflecting requesting potential emissions rates, which includes all heater units, boilers, diesel-fired emergency electrical generator engines, and flares.

Table 4 presents the TAPs and emission rates that exceeded the ELs. Modeling exemptions based on NSPS or NESHAP applicability were not requested nor applied for this project. TAPs exceeding the ELs were included in the ambient impact analyses for the normal and maximum flaring operating scenarios.

Table 4. FACILITYWIDE TAPs EMISSIONS EXCEEDING THE ELs				
Carcinogenic TAP[a]	**CAS[b] Number**	**Controlled Emission Rate[c]**	**Section 586 Screening Emission Level**	**Modeling Required?**
Arsenic	7440-38-2	Normal Operations – 2.4E-06 Maximum Flaring – 4.0E-07	1.5E-06	Yes
Benzene	71-43-2	Normal Operations – 5.0E-03 Maximum Flaring – 7.7E-03	8.0E-04	Yes
Cadmium	7440-43-9	Normal Operations –1.3E-05 Maximum Flaring – 2.2E-06	3.7E-06	Yes
Formaldehyde	50-00-0	Normal Operations – 3.6E-02 Maximum Flaring – 5.5E-02	5.1E-04	Yes

a. Toxic air pollutant.
b. Chemical Abstract Service.

3.0 Analytical Methods and Data

3.1 Modeling Methodology

This section describes the modeling methods used by the applicant's consultant, Stantec, to demonstrate compliance with applicable air quality standards.

3.1.1 Overview of Analyses

Stantec performed project-specific air impact analyses that were determined by DEQ to be reasonably representative of the facility, using established DEQ policies, guidance, and procedures. Results of the submitted analyses, in combination with DEQ's analyses, demonstrated compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 5 provides a brief description of parameters used in the modeling analyses.

Table 5. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
General Facility Location	Nampa, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 18081.
Meteorological Data	Boise	AERMET version 18081 was used to process five consecutive years—2012 through 2016. See Section 3.3 of this memorandum for additional details. Surface data from the Boise airport and upper air data from Boise, Idaho were used. Meteorological data were processed using the U star adjustment to more accurately estimate impacts during low wind conditions.
Terrain	Considered	Receptor elevations and hill height scales were determined using AERMAP version 18081 and a 1/3 arc second National Elevation Dataset (NED) file based on the NAD83 datum. The facility is located within Zone 11.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility and numerous nearby structures.
Receptor Grid	Grid 1	25-meter spacing minimum along the ambient air boundary
	Grid 2	50-meter spacing in a 1,250-meter (x) by 1,150-meter (y)

Table 5. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
		rectangular grid centered on the facility.
	Grid 3	100-meter spacing in a 1,800-meter (x) by 1,700-meter (y) rectangular grid centered on Grid 2.
	Grid 4	250-meter spacing in a 4,000-meter (x) by 4,000-meter (y) rectangular grid centered on Grid 3.
	Grid 5	500-meter spacing in a 7,500-meter (x) by 7,500-meter (y) rectangular grid centered on Grid 4.
	Grid 6	1,000-meter spacing in a 12,000-meter (x) by 12,000-meter (y) rectangular grid centered on Grid 5.
	Grid 7 Impact Resolution Grid	10-meter spacing in a 190-meter (x) by 190-meter (y) rectangular grid located along southwestern ambient air boundary.

3.1.2 Modeling Protocol

A modeling protocol was submitted to DEQ on April 19, 2019. On 10, 2019, DEQ issued a conditional modeling protocol approval letter for the PTC modification project to the City of Nampa and Stantec. Project-specific modeling was conducted using data and methods described in the modeling protocol and the *Idaho Air Modeling Guideline*[2].

3.1.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of air pollutant concentrations in ambient air be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple-source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

Stantec used AERMOD version 18081 to evaluate pollutant impacts to ambient air from the facility, which is the current version of AERMOD.

The Beta algorithms for treatment of point sources with horizontal release orientation or equipped with a rain cap that impedes the vertical momentum of exhaust plumes were adopted as guideline techniques with the revisions to Appendix W (Guideline on Air Quality Models). The Appendix W final rule was signed by the Administrator on December 2016, and published in January 17, 2017, in the Federal Register, with a delayed final effective date of May 22, 2017. This method eliminated momentum-induced plume rise while still accounting for thermal buoyancy-induced plume rise. Stantec applied the algorithms for horizontal stacks to three existing emergency electrical generator engine stacks (GEN1, GEN2, and GEN3), and applied the algorithms for capped stacks to the natural gas-fired VSB and LTS heater unit stacks (VSBHEAT1-VSBHEAT4, and LTSHEAT1-LTSHEAT4) and the LTS hot water heater (LTSHOTSY).

3.1.4 NOx Chemistry

NO_2 1-hour impacts can be assessed using a tiered approach to account for $NO/NO_2/O_3$ chemistry. Tier 1 assumes full conversion of NO to NO_2. Tier 2 Ambient Ratio Method (ARM) assumes a 0.80 default ambient ratio of NO_2/NOx. Tier 2 ARM2[3] was recently developed and replaces the previous ARM. Recent EPA guidance[4] on compliance methods for NO_2 states the following for ARM2:

"This method is based on an evaluation of the ratios of NO_2/NO_x from the EPA's Air Quality System (AQS) record of ambient air quality data. The ARM2 development report (API, 2013) specifies that ARM2 was developed by binning all the AQS data into bins of 10 ppb increments for NO_x values less than 200 ppb and into bins of 20 ppb for NO_x in the range of 200-600 ppb. From each bin, the 98th percentile NO_2/NO_x ratio was determined and finally, a sixth-order polynomial regression was generated based on the 98th percentile ratios from each bin to obtain the ARM2 equation, which is used to compute a NO_2/NO_x ratio based on the total NO_x levels."

Tier 3 methods account for more refined assessment of the NO to NO_2 conversion, using a supplemental modeling program with AERMOD to better account for $NO/NO_2/O_3$ atmospheric chemistry. Either the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM) can be specified within the AERMOD input file for the Tier 3 approach. EPA guidance (Memorandum: from Tyler Fox, Leader, Air Quality Modeling Group, C439-01, Office of Air Quality Planning and Standards, USEPA; to Regional Air Division Directors. *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard.* March 01, 2011) has not indicated a preference for one option over the other (PVMRM vs OLM) for particular applications.

The Tier 2 ARM2 and Tier 3 PVMRM and OLM methods are now regulatory options following the publication of final changes to EPA's Guideline on Air Quality Models on January 17, 2017. Stantec applied the Tier 3 PVMRM method for these analyses. DEQ's conditional modeling protocol approval letter approved the use of the Tier 3 PVMRM method but did not explicitly recommend its use over either the Tier 2 ARM2 or Tier 3 OLM compliance methods for this project.

DEQ performed verification NO_2 impact modeling analysis for the normal operating scenario using Tier 2 ARM2 and results demonstrated compliance (152.2 $\mu g/m^3$ maximum 1-hour NO_2 impact) with the 1-hour NO_2 NAAQS. DEQ also performed a sensitivity analysis and confirmed that the NO_2/NO_x in-stack-ratio (ISR) did not affect the NAAQS compliance conclusion. NO_2 NAAQS compliance is demonstrated when using Tier 2 ARM2 with regulatory default minimum and maximum ratio values of 0.5 and 0.9, respectively. The protocol approval listed a DEQ-approved NO_2/NO_x ISR of 0.2 for a boiler combusting a mixture of approximately 1/3 anaerobic digester biogas and 2/3 pipeline grade natural gas. An NO_2/NO_x ISR of 0.10 is the generally-approved value for natural gas combustion in boilers based on California Air Pollution Control Officers Association (CAPCOA) guidance[5], so the previous air permitting project actually assumed the biogas NO_2/NO_x ISR was approximately 0.35 to produce the boiler combustion composite NO_2/NO_x ISR value of 0.2 for a fuel feed of 1/3 biogas and 2/3 natural gas. Additional justification documentation on biogas combustion NO_2/NO_x ISR values is not readily available at this time.

The existing diesel-fired emergency electricity generator engines are exempted by DEQ policy[6] from inclusion in the 1-hour NO_2 NAAQS compliance demonstration analyses

3.2 Background Concentrations

A background concentration tool was used to establish ambient background concentrations for this project. DEQ has recently adopted the updated ambient background concentrations generated by the Idaho DEQ, Oregon Department of Environmental Quality, and Washington Department of Ecology, entirely replacing those backgrounds provided by the Northwest Airquest Consortium, referred to as the NW AIRQUEST ambient background lookup tables. The new ambient backgrounds were based in part on 2014-2017 ambient monitoring data, updated air pollutant emissions inventories and 4-

kilometer grid modeling data from Washington State University AIRPACT runs, and improved interpolation techniques. The NW AIRQUEST background concentration site is at: https://arcg.is/1jXmHH.

The 24-hour and annual SO_2 NAAQS have been revoked and are no longer in effect. Only the 1-hour average primary and 3-hour average secondary SO_2 NAAQS are in effect. DEQ concludes that the ambient background concentrations listed in the modeling protocol and in Table 6 below are appropriate.

Table 6. DEQ-RECOMMENDED AMBIENT BACKGROUND CONCENTRATIONS

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)[a, b]
PM_{10}[e]	24-hour	80.8
$PM_{2.5}$[f]	24-hour	26
	Annual	8
Ozone[c]	Annualized value	55 ppb[d]
NO_2[g]	1-hour	81.6 (43.4 ppb)
	Annual	23.9 (12.7 ppb)
CO[h]	1-hour	2,749 (2,400 ppb)
	8-hour	1,670 (1,460 ppb)
SO_2[i]	1-hour	16.7[j] (6.4 ppb)
	3-hour	18.6[k] (7.1 ppb)

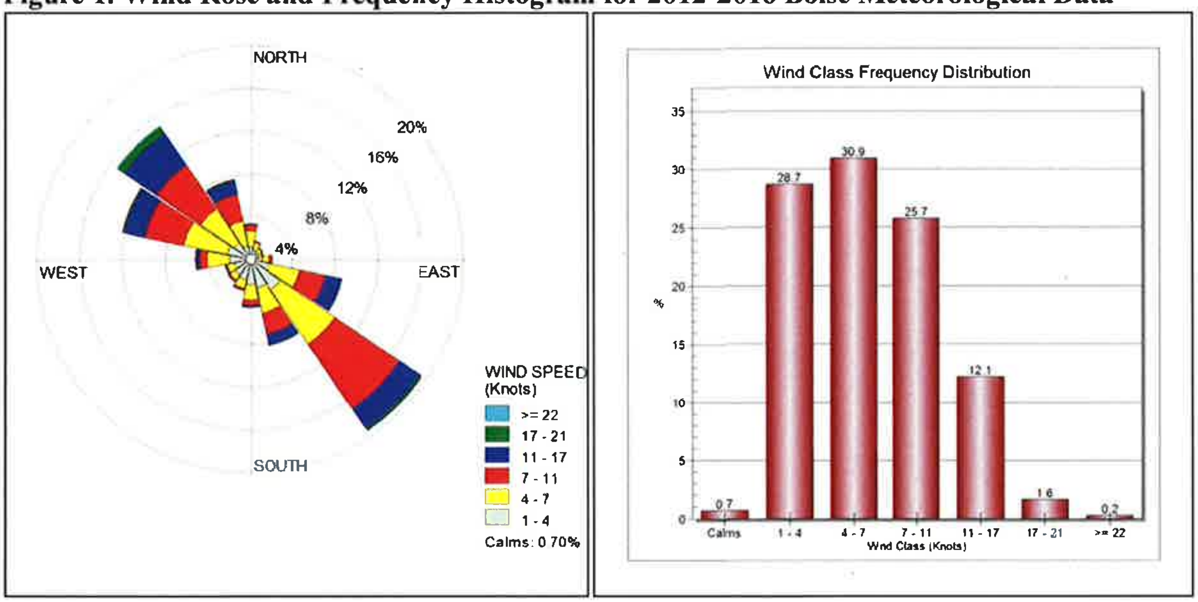
a. Micrograms per cubic meter, except where noted otherwise.
b. Idaho and Oregon DEQs and Washington Department of Ecology-generated ArcGIS Ambient Background Map, obtained at https://arcg.is/1jXmHH.
c. Ozone for use in 1-hour nitrogen dioxide modeling using Tier 3 Ozone Limiting Method or Tier 3 Plume Volume Molar Ratio Method.
d. Parts per billion by volume.
e. Particulate matter with an aerodynamic diameter of 10 microns.
f. Particulate matter with an aerodynamic diameter of 2.5 microns.
g. Nitrogen dioxide.
h. Carbon monoxide.
i. Sulfur dioxide.
j. Incorrectly listed as 12.5 $\mu g/m^3$ in DEQ's May 10, 2019, modeling protocol approval letter. Corrected value transmitted in a May 13, 2019, email.
k. Incorrectly listed as 13.9 $\mu g/m^3$ in DEQ's May 10, 2019, modeling protocol approval letter. Corrected value transmitted in a May 13, 2019, email.

3.3 Meteorological Data

DEQ provided Stantec with an AERMOD-ready meteorological dataset for use in the modeling analyses. The dataset was generated from monitored surface and Automated Surface Observing System (ASOS) data collected for five consecutive years for 2012 through 2016, at the Boise airport (FAA airport code KBOI, station ID 7268010-24131). Upper air data were obtained from the National Weather Service (NWS) Station site in Boise, Idaho (station ID 726810-24131). Surface characteristics were determined by DEQ staff using AERSURFACE version 13016. DEQ modeling staff evaluated annual moisture conditions for input to AERSURFACE based on a thirty year dataset of Boise airport precipitation data. Conditions were determined to be "wet" for 2012 and 2014, with 11.45 and 15.47 inches of precipitation, respectively. The years 2013, 2015, and 2016 were determined to be "average" years for precipitation. Average moisture conditions were established for years of moisture exceeding the 30^{th} percentile of the thirty year mean value of 11.2 inches. Continuous snow cover at the Boise airport site was determined to not have existed during these years. AERMINUTE version 15271 was used to process ASOS wind data for use in AERMET. AERMET version 16216 was used to process surface and upper air data and to generate a model-ready meteorological data input file. DEQ determined these data were representative for the project site and approved use of this dataset for the project.

DEQ provided separate datasets processed with and without the "adjust U star" (ADJ_U*) option with AERMET. The ADJ_U* option adjusts the surface friction velocity (u*) to address AERMOD's tendency to over predict from some sources under stable, low wind speed conditions. The method was approved as a regulatory guideline method in EPA's final rulemaking for changes to the 40 CFR 51, *Appendix W-Guideline on Air Quality Models*, published in the Federal Register on January 17, 2017. The submitted analyses were performed using the ADJ_U* option. Figure 1 presents wind direction, frequency, and magnitude of wind speed in the meteorological dataset's wind rose. Missing data and calms were each less than 1% of the total data, and a histogram of the distribution of the classes of wind speeds in the dataset.

Figure 1. Wind Rose and Frequency Histogram for 2012-2016 Boise Meteorological Data



3.4 Terrain Effects

Stantec used a National Elevation Dataset (NED) file, in "tif" format and in the NAD83 datum, to calculate elevations of receptors. A 1/3 arc second file provided 10-meter resolution of elevation data for the terrain preprocessor AERMAP version 11103. AERMAP extracts the elevations from the NED file and assigns them to each receptor in the modeling domain. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain. The terrain within the facility and surrounding the facility is quite flat, except for a section of land along the northern ambient air boundary that rises to meet Interstate Freeway 84.

3.5 Building Downwash Effects on Modeled Impacts

Potential downwash effects on the emissions plume were accounted for in the model by using building dimensions and locations in the model setup. The Building Profile Input Program for the PRIME downwash algorithm (BPIP-PRIME) was used to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and release parameters for input to AERMOD. Emission points, tanks, buildings, and receptors were included in the AERMAP setup. There are slight variations in building base elevations compared to stack base elevations for some sources, excluding the four boilers, but differences were small and consisted of stack base elevations set below the building base elevation. This will not result in the stack height above the modeled building tier height and will not inappropriately aid in plume dispersion. A post-project designed grade elevation diagram was not provided in the application materials, but spot checking the model setup values against Google Earth[7] data did not indicate there were any significant discrepancies. Therefore, DEQ did not revise or request revision of any assigned source, building, tank, or receptor elevations, and DEQ accepted the BPIP model setup as submitted.

Table 7 lists modeled tier heights for each building. Table 8 lists the modeled tier heights for each tank. All buildings and tanks were modeled with a single tier. New structures for the Phase II expansion project were included in the BPIP setup.

Table 7. BPIP STRUCTURE BASE ELEVATIONS AND TIER HEIGHTS

BPIP[a] Model Name	Building Description in BPIP	Building Base Elevation (m)[b]	Tier Height Above Base Elevation (m)
VSB-1	Vehicle Storage Building	749.24	8.53
LTS-1	Line Truck Shop	750.03	4.88
BOILER-1	Boiler	748.79	3.35
GENERATR-1	Generator	749.52	3.35
3000AST2-1		749.65	2.44
NITRI-1	Nitrification Basin	747.65	2.44
BLOWER-1	Blower Building	748.55	8.53
CHLORINE-1	Chlorine Building	748.12	6.10
CHLORBSN-1	Chlorine Contact Basin	747.75	1.22
SDB12_15-1	Sludge Drying Beds 12 - 15	747.39	0.30
RASBLDG-1	RAS Building	747.64	4.57
TRKLPUMP-1	Trickle Filter Pump Station	747.91	1.83
TRCKRECI-1	Trickle Recirculation Pump	748.76	3.96
DIGCONT-1		748.70	3.66
HEADWORK-1	Headworks	749.58	6.10
PRIPUMP1-1		748.37	4.27
ADMIN-1	Administration Building	749.13	5.99
PSLDPUMP-1	Primary Sludge pump#1	748.31	4.27
AERBASE-1	Aeration Basins	747.72	2.44
BLOWBLDG-1		747.93	5.49
PUMP#4-1	No4 Water pump station	747.67	4.27
POSTAER-1	Post Aeration Basin	747.64	1.22
CHLORMIX-1	Chlorine Mixing	747.69	1.22
PUMPSLG2-1	Primary Sludge Pump #2	748.96	4.27
CONTROL-1	Control Building	748.85	1.83
STOR_TNK-1	Digested Sludge Storage Tank	748.61	3.96
THICK-1	Floatation Thickner	748.56	8.53
SOLIDS-1	Solids Handling Facility	748.62	15.85

Table 7. BPIP STRUCTURE BASE ELEVATIONS AND TIER HEIGHTS			
BPIP[a] Model Name	Building Description in BPIP	Building Base Elevation (m)[b]	Tier Height Above Base Elevation (m)
STEAMTRT-1	Sidestream Treatment	748.22	9.14
TERTPMP-1	Tertiary Filtration Pump Station	748.24	4.27
T_FILT-1	Tertiary Filtration	748.11	6.10
IRRREUSE-1	Irrigation Reuse Pump Station	747.54	4.27
UV-1	UV Disinfection	747.53	5.49
INDUST-1	Industrial Reuse Pump Station	747.50	4.27

a. Building Profile Input Program.
b. Meters.

Table 8. BPIP Tanks Base Elevations, Heights, and Diameter				
BPIP[a] Model Name	Building Description in BPIP	Building Base Elevation (m)[b]	Tier Height Above Base Elevation (m)	Tank Diameter (m)
PRICLAR1	Primary Clarifier #1	748.61	0.91	25.60
PRICLAR2	Primary Clarifier #2	749.08	2.44	30.48
PRICLAR3	Primary Clarifier #3	749.37	2.44	33.53
SECDIG1	Secondary Digester #1	748.51	7.92	17.68
PRIDIG1	Primary Digester #1	748.59	7.62	22.86
PRIDIG2	Primary Digester #2	748.93	8.23	22.86
PRIDIG3	Primary Digester #3	749.11	10.67	21.34
FINCLAR1	Final Clarifier #1	747.7	0.91	36.58
FINCLAR2	Final Clarifier #2	748.29	0.91	36.58
FINCLAR3	Final Clarifier #3	747.73	0.91	36.58
FINCLAR4	Final Clarifier #4	748.09	0.91	36.58
PRIDIG4	Primary Digester #4	749.6	10.67	21.34
PRIDIG5	Primary Digester #5	749.16	10.67	21.34

a. Building Profile Input Program.
b. Meters.

3.6 Facility Layout

The project will require the construction of several new structures for the Phase II expansion project. All new buildings and changes to the existing facility layout were reflected in the model setup according to Stantec. The proposed and existing building, tank, and source locations appeared to match the plot plan diagram and model setup as exported to Google earth well. DEQ verified that the model setup ambient air boundary followed the external fence line visible in Google earth. Figure 2 presents an overhead view of the model setup of structures, emission points, and the ambient air boundary. The receptor grid near the facility is also included. Figure 4 presents a more detailed view of the most important emissions points for this project. LTS and VSB buildings and stack are not included in Figure 3. Figure 4 is intended to show the relationship of boiler stack release heights to tank structures close to the boiler stacks.

Figure 2. Ambient Air Boundary and Entire Facility Layout

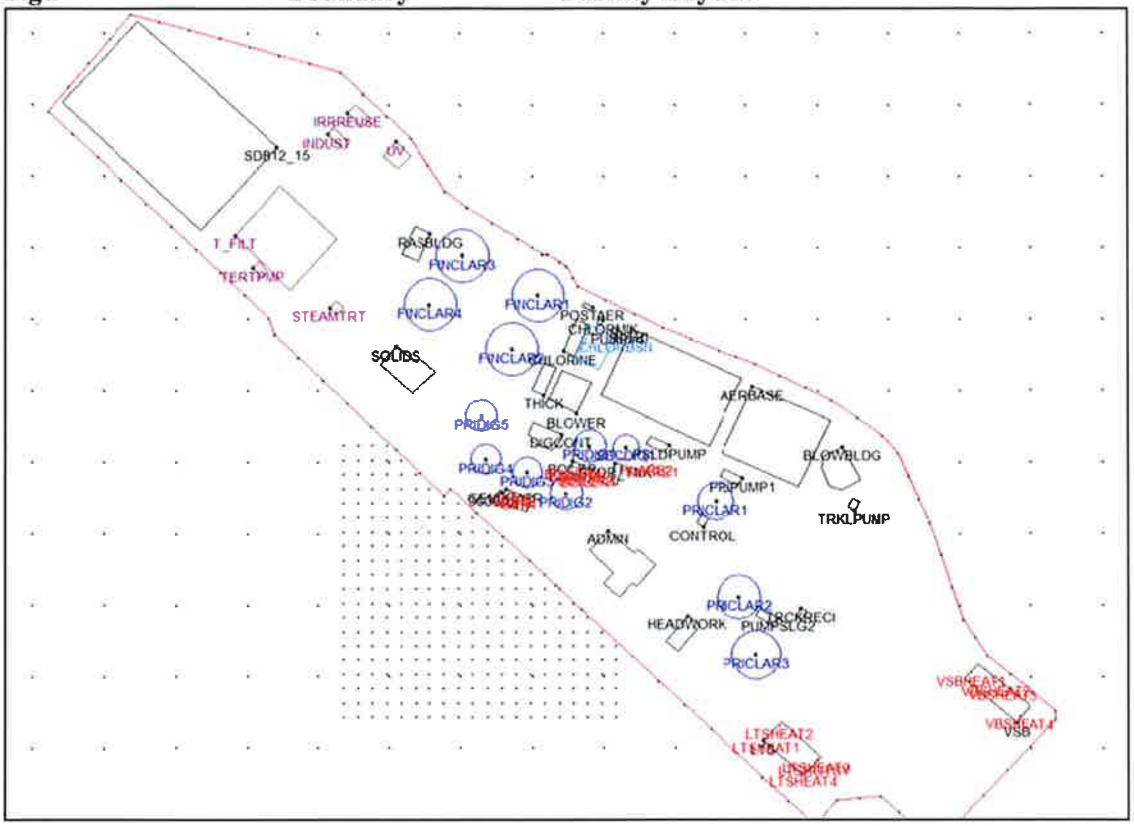


Figure 3. Primary Emission Units Locations

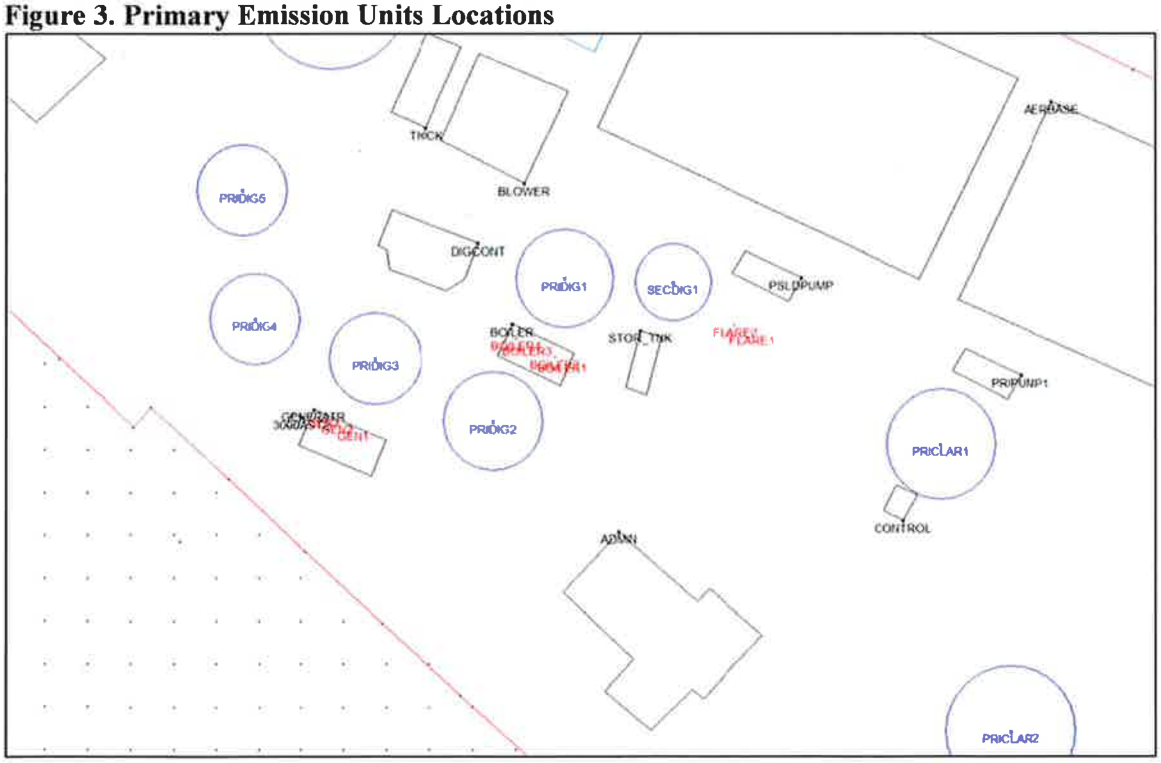


Figure 4. Three-Dimensional View of Release Heights for Boilers and Flares Amid Structures

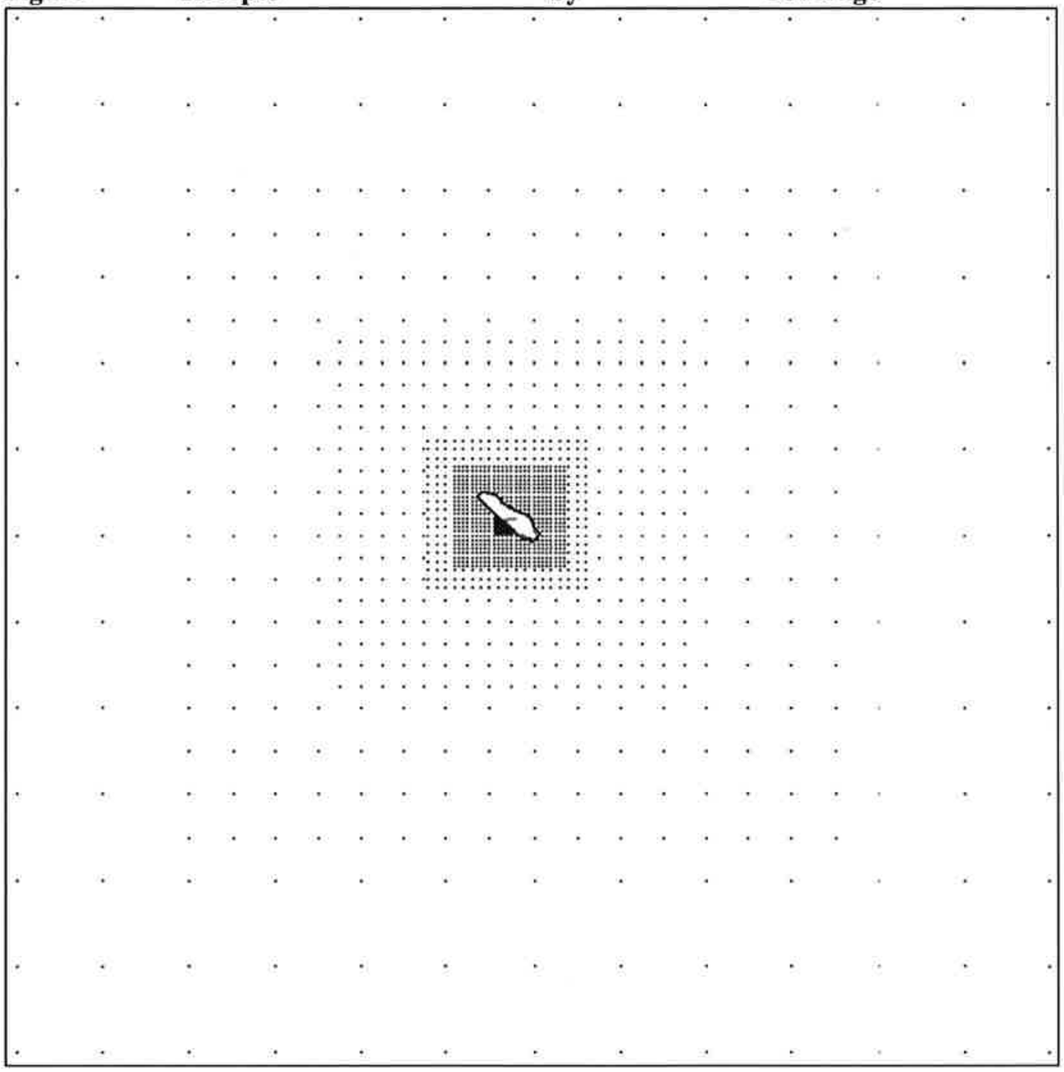
3.7 Ambient Air Boundary

Ambient air is defined by Section 006.10 of the Idaho *Air Rules* as "that portion of the atmosphere, external to buildings, to which the general public has access." The ambient air boundary used for this project was established as areas immediately exterior to the facility's property. The general public is precluded from access of the entire facility using existing fencing. DEQ concludes that the City of Nampa and Stantec appropriately addressed air pollutant impacts to areas considered as ambient air, as described in DEQ's *Modeling Guideline*[2].

3.8 Receptor Network

Table 5 describes the receptor network used in the submitted modeling analyses. The receptor grids used in the model provided good resolution of the maximum design concentrations for the project and provided extensive coverage. A fine grid was used to resolve the maximum ambient impacts, which were predicted to occur near the ambient air boundary. The full receptor grid was used for the NAAQS and TAPs ambient air impact analyses. DEQ determined that the receptor network was effective in reasonably assuring compliance with applicable air quality standards at all ambient air locations. The complete extent of the receptor grid is depicted below in Figure 6. A view of the more densely-spaced receptor grid located in the region of maximum design impacts close to the facility is shown above in Figure 3 in Section 3.6 of this memorandum.

Figure 6. Full Receptor Grid–12-Kilometer by 12-Kilometer Coverage



3.9 *Emission Rates*

Review and approval of estimated emissions is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emissions estimates is not addressed in this modeling review memorandum. DEQ air impact analyses review included verification that the potential emissions rates provided in the emissions inventory were properly used in the model. The modeled emission rates must represent the maximum allowable rate as averaged over the specified period.

Emission rates used for the dispersion modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emissions inventory. All modeled criteria air pollutant and TAP emission rates must be equal to or greater than the facility's potential emissions calculated in the PTC emissions inventory or proposed permit allowable emission rates.

Two operating scenarios were included in the analyses, intended to demonstrate that worst-case ambient impacts have been presented to support the NAAQS compliance demonstration. The first case reflects the normal operating scenario where all four of the Burnham boilers are fired at rated capacity on biogas and the excess biogas produced in the five anaerobic digester systems is incinerated by the two candlestick flares at partial capacity. The second scenario reflects maximum flaring operations, which is not intended to occur on a long-term basis so modeling of this scenario on the annual basis is a conservative approach. All four Burnham boilers are idled during this scenario with no emissions.

For both scenarios, all natural gas-fired heater units and the three diesel-fired internal combustion emergency electrical generator engines operate at rated capacity under the requested operating limits—24 hours/day and 8,760 hours/year for each of the natural gas-fired heaters, and, 6 hours/day and 100 hours/year for the diesel-fired engines.

Each of the four boilers can be fired on biogas as the primary fuel and natural gas as a backup fuel. A scenario reflecting simultaneous combustion of partial load on biogas with the balance made up of natural gas was not presented and it is assumed that at any time biogas is not used as a primary fuel only natural gas will be fired. The modeling demonstration modeled the worst-case emissions for the two fuels, which was biogas. This affected PM_{10}, $PM_{2.5}$, and SO_2 emissions only where the particulate matter emission factor for biogas was nearly double that for natural gas, and biogas contains up to 700 ppm_v H_2S, which is converted to SO_2 with an assumed 100% combustion conversion rate. Biogas and natural gas CO and NOx emission factors were identical. The boiler heat input capacity was represented as 2.6 MMBtu/hr for both fuel types.

3.9.1 Criteria Pollutant Emissions Rates for NAAQS Analyses

Significant impact level (SIL) analyses were not submitted for this project. Stantec elected to proceed directly to facility-wide NAAQS demonstrations due to numerous changes to the emission rates for the permitted emissions units.

Table 9 lists criteria pollutant continuous (24 hours/day) emission rates used to evaluate NAAQS compliance for standards with averaging periods of 24 hours or less, except where noted. Table 10 lists criteria pollutant continuous (8,760 hours/year) emission rates used to evaluate NAAQS compliance for standards with an annual averaging period. The modeled rates must be equal to or greater than permit allowable emissions for the listed averaging period.

Table 9. NAAQS SHORT-TERM CRITERIA POLLUTANT EMISSION RATES						
Emissions Point	Description	PM_{10}[d] (lb/hr)[c]	$PM_{2.5}$[e] (lb/hr)	NO_x[f] (lb/hr)	SO_2[g] (lb/hr)	CO[h] (lb/hr)
Operating Scenario 1 – 100% Boiler Load and Partial Flare Load						
BOILER1	Boiler #1	0.792	0.792	0.254	0.505	0.0963
BOILER2	Boiler #2	0.792	0.792	0.254	0.505	0.0963
BOILER3	Boiler #3	0.792	0.792	0.254	0.505	0.0963
BOILER4	Boiler #4	0.792	0.792	0.254	0.505	0.0963
FLARE1	Flare #1	0.113	0.113	0.607	1.53	3.3
FLARE2	Flare #2	0.113	0.113	0.607	1.53	3.3
Operating Scenario 2 – 100% Flares Load and 0% Boiler Load						
BOILER1	Boiler #1	0	0	0	0	0
BOILER2	Boiler #2	0	0	0	0	0
BOILER3	Boiler #3	0	0	0	0	0
BOILER4	Boiler #4	0	0	0	0	0
FLARE1	Flare #1	0.179	0.179	0.961	2.43	5.23
FLARE2	Flare #2	0.179	0.179	0.961	2.43	5.23
The following emissions points are not affected by a specific operating scenario						
VSBHEAT1	VSB Heater #1	0.0015	0.0015	0.0196	1.18E-04	0.0165
VBSHEAT2	VBS Heater #2	0.0015	0.0015	0.0196	1.18E-04	0.0165
VBSHEAT3	VBS Heater #3	0.0015	0.0015	0.0196	1.18E-04	0.0165
VBSHEAT4	VBS Heater #4	0.0015	0.0015	0.0196	1.18E-04	0.0165
LTSHEAT1	LTS Heater #1	0.0011	0.0011	0.0142	8.54E-05	0.0119
LTSHEAT2	LTS Heater #2	0.0011	0.0011	0.0142	8.54E-05	0.0119
LTSHEAT3	LTS Heater #3	0.0011	0.0011	0.0142	8.54E-05	0.0119
LTSHEAT4	LTS Heater #4	0.0011	0.0011	0.0142	8.54E-05	0.0119
LTSHOTSY	LTS Hotsy	0.0049	0.0049	0.0644	3.86E-04	0.0541
GEN1	Generator #1	0.03	0.03	0	0.0119	1.15
GEN2	Generator #2	0.03	0.03	0	0.0119	1.15
GEN3	Generator #3	0.03	0.03	0	0.0119	1.15

a. Significant impact level.
b. National ambient air quality standards.
c. Pounds per hour.
d. Particulate matter with a mean aerodynamic diameter of 10 microns or less.
e. Particulate matter with a mean aerodynamic diameter of 2.5 microns or less.
f. Nitrogen oxides.
g. Sulfur dioxide.
g. Carbon monoxide.
h. Existing source exempted from SIL analyses but subject to NAAQS analyses
i. Emergency electrical generator engines are exempted from modeling requirements for the 1-hour average NO_2 SIL and NAAQS in accordance with DEQ policy for testing and maintenance operation of 100 hours or less.[6]

Table 10. NAAQS ANNUAL CRITERIA POLLUTANT EMISSION RATES			
Emissions Point	Description	$PM_{2.5}$[a] (lb/hr)[b]	NO_x[c] (lb/hr)
Operating Scenario 1 – 100% Boiler Load and Partial Flare Load			
BOILER1	Boiler #1	0.033	0.253
BOILER2	Boiler #2	0.033	0.253
BOILER3	Boiler #3	0.033	0.253
BOILER4	Boiler #4	0.033	0.253
FLARE1	Flare #1	0.113	0.607
FLARE2	Flare #2	0.113	0.607
Operating Scenario 2 – 100% Flares Load and 0% Boilers Load			
BOILER1	Boiler #1	0	0
BOILER2	Boiler #2	0	0
BOILER3	Boiler #3	0	0
BOILER4	Boiler #4	0	0
FLARE1	Flare #1	0.179	0.961
FLARE2	Flare #2	0.179	0.961
Heaters and Generator Emissions for Both Scenarios			
VSBHEAT1	VSB Heater #1	0.0015	0.020
VBSHEAT2	VBS Heater #2	0.0015	0.020
VBSHEAT3	VBS Heater #3	0.0015	0.020
VBSHEAT4	VBS Heater #4	0.0015	0.020
LTSHEAT1	LTS Heater #1	0.0011	0.014
LTSHEAT2	LTS Heater #2	0.0011	0.014
LTSHEAT3	LTS Heater #3	0.0011	0.014
LTSHEAT4	LTS Heater #4	0.0011	0.014
LTSHOTSY	LTS Hotsy	0.0049	0.064
GEN1	Generator #1	0.0014	0.182
GEN2	Generator #2	0.0014	0.182
GEN3	Generator #3	0.0014	0.182

a. Particulate matter with a mean aerodynamic diameter of 2.5 microns or less.
b. Pounds per hour.
c. Nitrogen oxides.

3.9.2 Toxic Air Pollutant Emissions

The increase in emissions from the proposed project are required to demonstrate compliance with the toxic air pollutant (TAP) increments, with an ambient impact analyses for any applicable TAP having a requested potential emission rate that exceeds the screening emissions level (EL) specified by Idaho Air Rules Section 585 or 586. Review of the TAPs emissions inventory is the responsibility of the permit writer. Stantec stated that the facility-wide TAPs emissions would be modeled for this project rather than only the increase in TAP emissions. Modeled TAPs emission rates are listed in Table 11.

Table 11. TAPs POLLUTANT EMISSION RATES					
Model ID	Emission Unit Description	Arsenic (lb/hr)[a]	Benzene (lb/hr)	Cadmium (lb/hr)	Formaldehyde (lb/hr)
Normal Operating Scenario					
VSBHEAT1	VSB Heater #1	3.92E-08	4.12E-07	2.16E-07	1.47E-05
VBSHEAT2	VBS Heater #2	3.92E-08	4.12E-07	2.16E-07	1.47E-05
VBSHEAT3	VBS Heater #3	3.92E-08	4.12E-07	2.16E-07	1.47E-05
VBSHEAT4	VBS Heater #4	3.92E-08	4.12E-07	2.16E-07	1.47E-05
LTSHEAT1	LTS Heater #1	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHEAT2	LTS Heater #2	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHEAT3	LTS Heater #3	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHEAT4	LTS Heater #4	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHOTSY	LTS Hotsy	1.29E-07	1.35E-06	7.09E-07	4.83E-05
BOILER1	Boiler #1	5.10E-07	2.52E-05	2.81E-06	1.91E-04
BOILER2	Boiler #2	5.10E-07	2.52E-05	2.81E-06	1.91E-04
BOILER3	Boiler #3	5.10E-07	2.52E-05	2.81E-06	1.91E-04
BOILER4	Boiler #4	5.10E-07	2.52E-05	2.81E-06	1.91E-04
GEN1	Generator #1	0	6.93E-05	0	7.05E-06
GEN2	Generator #2	0	6.93E-05	0	7.05E-06
GEN3	Generator #3	0	6.93E-05	0	7.05E-06
FLARE2	Flare #2	0	0.00236	0	0.0174
FLARE1	Flare #1	0	0.00236	0	0.0174
Maximum Flaring Scenario					
VSBHEAT1	VSB Heater #1	3.92E-08	4.12E-07	2.16E-07	1.47E-05
VBSHEAT2	VBS Heater #2	3.92E-08	4.12E-07	2.16E-07	1.47E-05
VBSHEAT3	VBS Heater #3	3.92E-08	4.12E-07	2.16E-07	1.47E-05
VBSHEAT4	VBS Heater #4	3.92E-08	4.12E-07	2.16E-07	1.47E-05
LTSHEAT1	LTS Heater #1	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHEAT2	LTS Heater #2	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHEAT3	LTS Heater #3	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHEAT4	LTS Heater #4	2.84E-08	2.99E-07	1.56E-07	1.07E-05
LTSHOTSY	LTS Hotsy	1.29E-07	1.35E-06	7.09E-07	4.83E-05
GEN1	Generator #1	0	6.93E-05	0	7.05E-06
GEN2	Generator #2	0	6.93E-05	0	7.05E-06
GEN3	Generator #3	0	6.93E-05	0	7.05E-06
FLARE2	Flare #2	0	0.00374	0	0.0275
FLARE1	Flare #1	0	0.00374	0	0.0275

a. Pounds per hour.

3.10 Emission Release Parameters

Tables 12 and 13 list emission release parameters for modeled sources at the Nampa WWTP facility for the NAAQS and TAPs analyses in metric and English units, respectively.

Table 12. EMISSION POINT RELEASE PARAMETERS – METRIC									
Release Point	Source Description	UTM Coordinates[a]		Stack Base Elevation (m)	Stack Height (m)	Stack Gas Temp (K)[c]	Stack Exit Velocity (m/s)[d]	Stack Diam (m)	Stack Release Type
		Easting (m)[b]	Northing (m)						
Normal Operating Scenario – 4 Boilers and Flares and Flares at Partial Capacity									
BOILER1	Boiler #1	533,739.64	4,827,192.41	748.8	8.08	487.0	4.84	0.305	Default[e]
BOILER2	Boiler #2	533,737.67	4,827,193.19	748.8	8.08	487.0	4.84	0.305	Default[e]
BOILER3	Boiler #3	533,731.29	4,827,196.38	748.8	7.77	487.0	4.84	0.305	Default[e]
BOILER4	Boiler #4	533,728.80	4,827,197.47	748.8	7.16	487.0	4.84	0.305	Default[e]
FLARE2	Flare #2	533,780.18	4,827,200.55	748.5	7.44	1,273.0	6.76	0.524	Default[e]
FLARE1	Flare #1	533,784.20	4,827,198.78	748.5	7.44	1,273.0	6.76	0.524	Default[e]
Operating Scenario 2 – Flares at Full Biogas Generation Capacity and Boilers Idle									
FLARE2	Flare #2	533,780.18	4,827,200.55	748.5	7.44	1,273.0	6.76	0.524	Default[e]
FLARE1	Flare #1	533,784.20	4,827,198.78	748.5	7.44	1,273.0	6.76	0.524	Default[e]
None of the following emissions points is affected by a specific operating scenario									
VSBHEAT1	VSB Heater #1	534,007.56	4,827,052.86	748.35	9.75	304.7	2.00	0.127	Raincap
VBSHEAT2	VBS Heater #2	534,025.16	4,827,045.77	748.92	9.75	304.7	2.00	0.127	Raincap
VBSHEAT3	VBS Heater #3	534,029.99	4,827,043.00	749.13	9.75	304.7	2.00	0.127	Raincap
VBSHEAT4	VBS Heater #4	534,041.75	4,827,022.55	749.25	9.75	304.7	2.00	0.127	Raincap
LTSHEAT1	LTS Heater #1	533,864.27	4,827,006.11	749.98	5.49	301.2	2.50	0.102	Raincap
LTSHEAT2	LTS Heater #2	533,873.72	4,827,015.74	749.8	5.49	301.2	2.50	0.102	Raincap
LTSHEAT3	LTS Heater #3	533,899.46	4,826,992.45	749.78	5.49	301.2	2.50	0.102	Raincap
LTSHEAT4	LTS Heater #4	533,890.01	4,826,982.30	750.06	5.49	301.2	2.50	0.102	Raincap
LTSHOTSY	LTS Hotsy	533,897.71	4,826,990.35	749.82	6.40	533.2	2.17	0.305	Raincap
GEN1	Generator #1	533,690.83	4,827,176.54	749.21	6.55	781.9	92.20[f]	0.197	Horizontal
GEN2	Generator #2	533,687.17	4,827,178.18	749.33	6.55	781.9	92.17[f]	0.197	Horizontal
GEN3	Generator #3	533,683.90	4,827,179.65	749.44	6.55	781.9	92.17[f]	0.197	Horizontal

a. Universal Transverse Mercator, NAD83 horizontal datum, Zone 11.
b. Meters.
c. Kelvin.
d. Meters per second.
e. Default release represents a vertical orientation with an uninterrupted release point.
f. This velocity exceeds the DEQ standard cutoff of 50 m/s warranting additional justification and scrutiny. The horizontal release orientation inhibits the momentum buoyancy of the generator engine exhaust plume, minimizing the effect of a high velocity value.

Table 12. EMISSION POINT RELEASE PARAMETERS – ENGLISH									
Release Point	Source Description	UTM Coordinates[a]		Stack Base Elevation (ft)[c]	Stack Height (ft)	Stack Gas Temp (°F)[d]	Stack Flow Velocity (fps)[e]	Stack Diam (ft)	Stack Release Type
		Easting (m)[b]	Northing (m)						
Normal Operating Scenario – 4 Boilers and Flares and Flares at Partial Capacity									
BOILER1	Boiler #1	533,739.64	4,827,192.41	2,456.6	26.5	417.0	15.87	1.00	Default[f]
BOILER2	Boiler #2	533,737.67	4,827,193.19	2,456.6	26.5	417.0	15.87	1.00	Default[f]
BOILER3	Boiler #3	533,731.29	4,827,196.38	2,456.7	25.5	417.0	15.87	1.00	Default[f]
BOILER4	Boiler #4	533,728.80	4,827,197.47	2,456.7	23.5	417.0	15.87	1.00	Default[f]
FLARE2	Flare #2	533,780.18	4,827,200.55	2,455.7	24.4	1,831.7	22.18	1.72	Default[f]
FLARE1	Flare #1	533,784.20	4,827,198.78	2,455.7	24.4	1,831.7	22.18	1.72	Default[f]
Operating Scenario 2 – Flares at Full Biogas Generation Capacity and Boilers Idle									
FLARE2	Flare #2	533,780.18	4,827,200.55	2,455.7	24.4	1,831.7	22.18	1.72	Default[f]
FLARE1	Flare #1	533,784.20	4,827,198.78	2,455.7	24.4	1,831.7	22.18	1.72	Default[f]
None of the following emissions points is affected by a specific operating scenario									
VSBHEAT1	VSB Heater #1	534,007.56	4,827,052.86	2,455.2	32.0	88.8	6.56	0.42	Raincap
VBSHEAT2	VBS Heater #2	534,025.16	4,827,045.77	2,457.1	32.0	88.8	6.56	0.42	Raincap

Table 12. EMISSION POINT RELEASE PARAMETERS – ENGLISH									
Release Point	Source Description	UTM Coordinates[a]		Stack Base Elevation (ft)[c]	Stack Height (ft)	Stack Gas Temp (°F)[d]	Stack Flow Velocity (fps)[e]	Stack Diam (ft)	Stack Release Type
		Easting (m)[b]	Northing (m)						
VBSHEAT3	VBS Heater #3	534,029.99	4,827,043.00	2,457.8	32.0	88.8	6.56	0.42	Raincap
VBSHEAT4	VBS Heater #4	534,041.75	4,827,022.55	2,458.2	32.0	88.8	6.56	0.42	Raincap
LTSHEAT1	LTS Heater #1	533,864.27	4,827,006.11	2,460.6	18.0	82.5	8.20	0.33	Raincap
LTSHEAT2	LTS Heater #2	533,873.72	4,827,015.74	2,460.0	18.0	82.5	8.20	0.33	Raincap
LTSHEAT3	LTS Heater #3	533,899.46	4,826,992.45	2,459.9	18.0	82.5	8.20	0.33	Raincap
LTSHEAT4	LTS Heater #4	533,890.01	4,826,982.30	2,460.8	18.0	82.5	8.20	0.33	Raincap
LTSHOTSY	LTS Hotsy	533,897.71	4,826,990.35	2,460.0	21.0	500.0	7.13	1.00	Raincap
GEN1	Generator #1	533,690.83	4,827,176.54	2,458.0	21.5	947.8	302.50[g]	0.65	Horizontal
GEN2	Generator #2	533,687.17	4,827,178.18	2,458.4	21.5	947.8	302.41[g]	0.65	Horizontal
GEN3	Generator #3	533,683.90	4,827,179.65	2,458.8	21.5	947.8	302.41[g]	0.65	Horizontal

a. Universal Transverse Mercator, NAD83 horizontal datum, Zone 11
b. Meters.
c. Feet.
d. Degrees Fahrenheit.
e. Feet per second.
f. Default release represents a vertical orientation with an uninterrupted release point.
g. This velocity exceeds the DEQ standard cutoff of 50 m/s (164 fps) warranting additional justification and scrutiny. The horizontal release orientation inhibits the momentum buoyancy of the generator engine exhaust plume, minimizing the effect of a high velocity value.

DEQ's permitting policies and guidance require that each permit application have stand-alone documentation to support the appropriateness of release parameters used in the air impact analyses. The modeling report submitted to DEQ by the City of Nampa and Stantec provided justification and documentation of assumptions and data supporting key release parameters used to model these point sources.

- **Dual fuel-fired Boilers 1 – 4 (BOILER1, BOILER2, BOILER3, AND BOILER4)**
  The four boilers are identical with heat input capacities of 2.60 MMBtu/hr while fired on either biogas or pipeline grade natural gas.

  Supporting documentation for the biogas combustion exhaust flow rate and exit temperature at 100%, 75%, 50%, and 25% load conditions was provided by the equipment vendor, Folsom Industrial, in email communications to Stantec and the City of Nampa. The data included the following for biogas combustion:

  - 100% load: 417°F and 748 ACFM.
  - 75% load: 354°F and 518 ACFM.
  - 50% load: 287°F and 317 ACFM.
  - 25% load: 216°F and 317 ACFM.

  Calculations were not submitted with the listed biogas combustion release parameters to allow review of methods and assumptions. However, the ambient impacts from the boilers were regarded as conservative predictions based on the observation that the boiler stack exhaust plumes were influenced by structure-induced downwash primarily due to tanks rather than rectangular buildings. BPIP-PRIME treats tank-induced downwash conservatively. Air flow around tanks is increased in comparison to rectangular buildings, which would tend to reduce impacts for tank-induced downwash.

Another conservative factor is that only three of the four boilers is likely to operate at any given time, so actual impacts from the group of boilers is conservative in this respect.

Biogas is the primary boiler fuel and natural gas is the backup fuel. DEQ confirmed that the exhaust flow rate for full load natural gas combustion was higher than the latest Folsom Industrial-supplied flow rate for biogas. Exit temperature for natural gas firing was not supplied by Folsom Industrial.

Stack release height values and exit diameters for each of the boilers was established by Stantec by on-site measurement according to the email documentation submitted in the modeling report. Each boiler stack base elevation appropriately matched the building base elevations. These emissions units provide the greatest contribution to the design concentrations.

- **Emergency Electrical Generator Engines (GEN1, GEN2, and GEN3)**
  The three generator engines are identical diesel-fired units designed to generate 800 kW at 100% load for each unit. Developed engine horsepower at 100% load is 1,191 bhp. Emission rates for 100% load were modeled for the analyses. Supporting documentation included a Caterpillar manufacturer's specification sheet. The "reference exhaust stack diameter" listed by Caterpiller was 10 inches and the volumetric exhaust flow rate at 100% load was 5,932 ACFM. The modeled exit diameter was 7.75 inches and the modeled volumetric flow rate was 5,932 ACFM, which resulted in an exit velocity of 92.2 m/s. The modeled stack temperature of 948 °F was taken by Stantec from the Caterpillar specification sheet for the 100% load "engine exhaust temperature." For comparison, the listed manifold temperature at full load condition was 1,223 °F.

  Stantec staff provided email documentation, as shown in Figure 7 below, of results of their field verification for the exit diameter and release heights of these stacks. Release orientation was not described but DEQ accepted that the stacks each have a horizontal release (a conservative condition).

  DEQ typically establishes an upper threshold of 50 meters/second exit velocity for all exhaust stacks, with additional justification required for values exceeding this threshold. DEQ generally considers cooling of the exhaust stream to occur over the length of travel through stack from attachment at the engine outlet to the point of release, which often includes transport through exhaust muffler systems. DEQ conducted a sensitivity analysis to analyze the effect of using more conservative release parameters. using the horizontal release option, a 7.75-inch exit diameter, reduced temperature of 500 °F, a 45 meters/second exit velocity (2,902 ACFM flow rate) for the 24-hour average $PM_{2.5}$ NAAQS setup for the Normal Operating scenario. There were no notable increases in impacts when modeling with the more conservative release parameters. The diesel-fired emergency generator engines were exempted by DEQ policy from the 1-hour NO_2 NAAQS compliance demonstration. DEQ concluded the diesel-fired emergency generator engine release parameters are adequately justified using the permit application information and DEQ sensitivity analyses.

Figure 7. Stantec Results of Field Verification of Data

From: Smith, Nickolas
To: Clark, Erik
Cc: Zantos, Jay
Subject: Exhaust Information
Date: Monday, April 22, 2019 11:31:07 AM
Attachments: image001.png

Hey Eric,

Jay and I just got back from Nampa WWTP and measured the following:

Boiler Exhausts (from West to East)

- 12.5' off roof and 12" diameter (26.5' above grade)
- 12.5' off roof and 12" diameter (26.5' above grade)
- 11.5' off roof and 12" diameter (25.5' above grade)
- 9.5' off roof and 12" diameter (23.5' above grade)

Generator Exhausts

- All 3 – 5.5' above roof, 21.5' above grade, 7.75" diameter

Hope that is what you needed.

Nick Smith, P.E., PMP
Project Management & Commercial Leader
Stantec Consulting Services Inc.
727 E. Riverpark Lane, Suite 150, Boise, ID 83706
Phone: (208) 345-5865 or (208) 388-4306
Cell: (208) 340-8284
nickolas.smith@stantec.com

- **Candlestick Flares (FLARE1 and FLARE2).**
  Candlestick flares are open flares without enclosures, which are modeled as point sources with uninterrupted releases. Stantec used the Iowa Department of Natural Resources methods as a basis for estimating release height and stack diameter for the two elevated candlestick flares. Detailed documentation of the flare release parameter calculations was included in Section 4.3 of the modeling report and included estimates for the two operating scenarios. Each of the two flares is assumed to incinerate 9 MMBtu/hr under the normal operating scenario and 14.1 MMBtu/hr under the maximum flaring scenario. The City of Nampa will install two identical flares immediately next to each other. Physical stack release heights of 18.4 feet above grade for both the existing and new flare were used in the effective release height calculations. The source of the physical release heights was not described but the value appears reasonable given the safety considerations for operation of open flares within a facility and matches the 2011 permitting project physical release height.

  The flare effective release height parameters were based on physical release height, the heat input of the waste gas being flared, release temperature, and the assumed amount of heat lost to radiation heat transfer. The Iowa DNR method use empirical relationships to calculate effective release heights and stack diameters for the modeling parameters. Stantec applied the SCREEN3 default values for radiation of 55% in the calculations, which is generally considered to be a relatively conservative value for most gases. Stack diameters using the Iowa DNR method are based on heat release rate without regard to the physical burner diameter, and rely on an assumed release temperature and an assumed exit velocity. The EPA SCREEN3 flare temperature of 1,832°F and exit velocity of 20 meters/second were used in the estimates of the effective stack diameter. An exit velocity of 20 meters/second is a standard assumption for modeling open flares.

The calculated and modeled release parameters for each of the two flares under the normal and maximum operating scenarios are listed in Table 13. Stantec modeled identical release parameters for both normal and maximum flaring scenarios. DEQ concluded the modeled flare release parameters were adequately supported or were conservative as a whole based on the exit velocities and volumetric flow rates represented in the modeling analyses.

Table 13. FLARE RELEASE PARAMETRS

Source / Scenario	Calculated Effective Exit Diameter (ft)[a]	Calculated Effective Release Height (ft)	Calculated Volumetric Flow Rate at SCREEN3 20 m/s[b] Exit Velocity (ACFM)[c]
Flare 1 & 2 – Normal[d]	1.72	24.4	9,149
Flare 1 & 2– Maximum Flaring[e]	2.16	25.9	14,427
Source / Scenario	**Modeled Diameter (ft)**	**Modeled Release Height (ft)**	**Modeled Volumetric Flow Rate (ACFM)**
Flare 1 & 2 – Normal[d]	1.72	24.4	3,093[f]
Flare 1 & 2 – Maximum Flaring[e]	1.72	24.4	3,093[f]

a. Feet.
b. Meters per second.
c. Actual cubic feet per minute.
d. Each flare assumed to combust 9 MMBtu/hr biogas.
e. Each flare assumed to combust 14.1 MMBtu/hr biogas.
f. The corresponding exit velocity is 6.8 m/s.

- **LTS Heaters, LTS Hotsy, and VBS Heaters Stacks**
  The four LTS heaters are natural gas-fired heaters each rated at 0.145 MMBtu/hr input. The single natural gas-fired LTS Hotsy pressure washer heater is rated at 0.657 MMBtu/hr heat input. The four natural gas-fired VSB heaters are each rated at 0.20 MMBtu/hr heat input.

  The modeling protocol submitted by Stantec stated that all stacks release heights and diameters had been field-verified. The LTS heaters and Hotsy stacks are located on top of the LTS building with stack release heights of 18 feet, which is approximately 2 feet above the modeled 16 feet tier height representing roofline of the structure. The LTS Hotsy pressure washer heater stack was placed 5 feet above roofline with a height of 21 feet. Base elevations of all five LTS stacks closely matched the LTS building base elevation.

  The VSB heaters stacks were modeled with release heights 4 feet above the tier height for the VSB roofline. Stack base elevations VSBHEAT1 and VSBHEAT2 were slightly below the VSB buildings base elevations, which will be conservative for ambient impacts and the base elevations of other stacks matched building base elevation.

  LTS stacks were modeled with 4-inch diameters and VSB heater stacks were modeled with 5-inch diameters, which match the manufacturer's specification sheet values. LTSHOTSY stack diameter was field measured according to Stantec documentation.

  All LTS and VSB stacks are currently equipped with rain caps and will remain equipped with

rain caps after permit issuance. Exit velocity and flow rate value effects on momentum plume rise were minimized due to modeling all VSB heater stacks as a capped release. Exhaust flow rates for the heaters in the final August 8, 2019, and August 15, 2019, submittals matched EPA F-Factor flow rates for natural gas. These flow rates corrected the previous submittal's exhaust flow rates that were based on prior analyses and volume of air provided to the conditioned space rather than the combustion flue. Release temperatures appeared to be conservative for all heaters with LTS heaters modeled at 83°F and VSB heaters modeled at 89°F. The Hotsy pressure washer stack used an assumed exit temperature value originated with the facility's initial PTC project. The modeling report contained a 2011-era vendor email documentation listed an exit temperature value of 500°F. This temperature provides considerable thermal buoyancy to the rain-capped LTSHOTSY plume. DEQ accepted this value without additional validation because, in part, it was close to the temperature used for the Burnham boilers, and primarily, because this stack's impacts do not contribute greatly to any of the project's design concentrations due to proximity and relatively small emission rates.

DEQ concludes that the release parameters used in the modeling analyses were adequately supported and were appropriate for estimating predicted ambient impacts for this project.

4.0 Results for Air Impact Analyses

The submitted analyses used two operating scenarios for the project to evaluate worst-case ambient impacts: 1) maximum normal operations; 2) maximized flaring operations.

4.1 Results for Significant Impact Analyses

SIL analyses were not performed for this project. Requested post-project potential to emit was modeled to demonstrate compliance with all applicable NAAQS without performing a preliminary SIL analyses.

4.2 Results for Cumulative NAAQS Impact Analyses

The results for the cumulative impact analyses are listed in Table 14. Ambient impacts for the facility were below the applicable NAAQS for both operating scenarios. Maximum biogas generated by modified facility was reflected in both modeled operating scenarios. The "normal" operating scenario reflects all four boilers operating at rated capacity and partial load flaring to incinerate unutilized biogas. The maximum flaring scenario reflects full load incineration of all biogas generated by the facility with all four boilers nonoperational.

The June 19, 2019, submittal provided the final modeled impacts for the maximum flaring scenario for 1-hour and 8-hour CO, 1-hr and annual average NO_2, 24-hour and annual average $PM_{2.5}$, and 24-hour average PM_{10}.

The August 8, 2019, and August 15, 2019, submittals provided the final modeled impacts for the maximum flaring 1-hour and 3-hour average SO_2, and the final modeled impacts for the normal operating scenario for all criteria pollutants and all TAPs.

Table 14. RESULTS FOR CUMULATIVE IMPACT ANALYSES

Pollutant	Averaging Period	Operating Scenario	Modeled Design Value Concentration (µg/m^3)[a]	Background Concentration (µg/m^3)	Maximum Total Ambient Impact (µg/m^3)	NAAQS[b] (µg/m^3)	Percent of NAAQS
NO_2[c]	1-hour	Normal	152.2[h,o] (148.0)[h,p]	81.6 (43.4 ppb)	152.2	188	81%
		Maximum Flaring	131.6[h]	Included in design concentration	131.6		70%
	Annual	Normal	6.1[i]	23.9	30.0	100	30%
		Maximum Flaring	5.3[i]		29.2		29%
$PM_{2.5}$[d]	24-hour	Normal	2.1[j]	26	28.1	35	80%
		Maximum Flaring	1.9[j]		27.9		80%
	Annual	Normal	0.6[k]	8	8.6	12	72%
		Maximum Flaring	0.5[k]		8.5		71%
PM_{10}[e]	24-hour	Normal	3.2[l]	80.8	84.0	150	56%
		Maximum Flaring	3.1[l]		83.9		56%
SO_2[f]	1-hour	Normal	175.8[m]	16.7	192.5	196	98%
		Maximum Flaring	112.0[m,o] (117.5)[m,p]		142.6		73%
	3-hour	Normal	125.9[n,o] (116.3)[n,p]	18.6	130.6	365	36%
		Maximum Flaring	99.7[n]		118.3		32%
CO[g]	1-hour	Normal	437.1[n]	2,748	3,185	40,000	8%
		Maximum Flaring	343.4[n]		3,091		8%
	8-hour	Normal	104.8[n]	1,672	1,777	10,000	18%
		Maximum Flaring	160.4[n]		1,832		18%

a. Micrograms per cubic meter.
b. National ambient air quality standards.
c. Nitrogen dioxide.
d. Particulate matter with an aerodynamic diameter of 2.5 microns or less.
e. Particulate matter with an aerodynamic diameter of 10 microns or less.
f. Sulfur dioxide.
g. Carbon monoxide.
h. Modeled design value is the maximum 5-year mean of 8th highest daily 1-hour maximum impacts for each year of a 5-year meteorological dataset.
i. Maximum annual average impact from 5 individual years of meteorological data.
j. Modeled design value is the maximum 5-year mean of 8th highest 24-hour average impacts for each year of a 5-year meteorological dataset.
k. Maximum annual impact averaged over 5 years of meteorological data.
l. Design value is the 6th highest impact from a 5-year meteorological dataset.
m. Design value is the maximum 5-year mean of 4th highest daily 1-hour maximum impacts for each year of a 5-year meteorological dataset.
n. Maximum second highest impact of five individual years of meteorological data.
o. Value from electronic modeling AERMOD output file. This value was used to review NAAQS compliance.
p. Value from Tables 9 and 10, August 8, 2019, final modeling report for Nampa WWTP Project 62235.

4.3 *Results for TAPs Impact Analyses*

Stantec modeled facility-wide potential emissions from all facility emissions units under the two previously identified operational scenarios. Requested allowable biogas production was reflected in the modeled emission rates for the two flares. All natural gas-fired heaters were modeled at rated capacity.

Table 15 lists the maximum modeled impacts for specific TAPs. All modeled impacts are below applicable AACCs.

Table 15. TAP AIR IMPACT ANALYSIS RESULTS					
TAP	**CAS[a] No.**	**Averaging Period**	**Maximum Modeled Impact ($\mu g/m^3$)[b]**	**AACC[c] ($\mu g/m^3$)**	**Percent of AACC**
Normal Operations					
Arsenic	7440-38-2	Annual	1E-05	2.3E-04	4%
Benzene	71-43-2	Annual	5.25E-03	1.2E-01	4%
Cadmium	7440-43-9	Annual	6E-05	5.6E-04	11%
Formaldehyde	50-00-0	Annual	3.8E-02	7.7E-02	49%
Maximum Flaring					
Arsenic	7440-38-2	Annual	1E-05	2.3E-04	4%
Benzene	71-43-2	Annual	7.86E-03	1.2E-01	7%
Cadmium	7440-43-9	Annual	5E-05	5.6E-04	9%
Formaldehyde	50-00-0	Annual	5.7E-02	7.7E-02	74%

a. Chemical Abstract Service.
b. Micrograms per cubic meter.
c. Carcinogenic TAP. Modeled impact and AACC represent an 8,760-hour averaged concentration.

4.4 DEQ Sensitivity Analyses

4.4.1 1-Hour NO_2 NAAQS Sensitivity Analyses

DEQ used normal operations scenario emissions and release parameter setup in a 1-hour average NO_2 sensitivity analysis to evaluate the effect of using standard default NO_2/NOx ISRs for all sources, including the biogas-fired boilers. Tier 2 ARM2 is a regulatory default method and is routinely approved without additional justification for use in 1-hour NO_2 impact analyses, and DEQ approval is not required for use of the default minimum ratio values of 0.5 and 0.9, respectively. An alternative NO_2/NO_x ISR for the biogas combustion in boilers is not necessary to establish DEQ-approved compliance with the 1-hour NO_2 NAAQS. All emission rates and release parameters were identical to the 1-hour NO_2 Tier 3 PVMRM model setup submitted by Stantec. The predicted design impact for the DEQ sensitivity analysis matched the August 8, and August 15, 2019, final impact analysis submittals for the project. DEQ concluded that ambient impacts for the project comply with the NAAQS. The results of the 1-hour NO_2 sensitivity analysis are listed in Table 16.

Table 16. RESULTS FOR DEQ 1-HOUR AVERAGE NO_2 SENSITIVITY ANALYSES							
Pollutant	**Averaging Period**	**Operating Scenario**	**Modeled Design Value Concentration ($\mu g/m^3$)[a]**	**Background Concentration ($\mu g/m^3$)**	**Maximum Total Ambient Impact ($\mu g/m^3$)**	**NAAQS[b] ($\mu g/m^3$)**	**Percent of NAAQS**
NO_2[c]	1-hour	Normal	152.2[h]	81.6 (43.4 ppb) Included in design concentration	152.2	188	81%

a. Micrograms per cubic meter.
b. National ambient air quality standards.
c. Nitrogen dioxide.
d. Modeled design value is the maximum 5-year mean of 4th highest daily 1-hour maximum impacts for each year of a 5-year meteorological dataset.

4.4.2 1-Hour SO_2 NAAQS Sensitivity Analyses

DEQ's July 17, 2019, incompleteness letter requested that maximum emission rates be modeled with typical release parameters, or, alternatively, that a multiple load analysis be submitted. A full load analysis was then submitted using full load release parameters and emission rates only. Additional analyses reflecting partial load emissions and release parameters were not submitted to support the project's compliance demonstration. The application indicated that when boilers are operated, they operate at near 100 % load and do not ever operate at intermediate load. DEQ conducted two sensitivity analyses based on 75% load emissions rates and release parameters for the boilers while fired on biogas at the allowable H_2S limit of 700 ppm_v. Release parameters for the boilers 75% load case were taken from the August 8, 2019, incompleteness response submittal's justification materials (Folsom Industrial email to Stantec). Case 1 included all four boilers at 75% load, and Case 2 included 3 boilers at 75% load with the fourth boiler idled. Each operational boiler stack was modeled with 0.379 lb/hr of SO_2 emissions, an exit temperature of 354°F, and an exhaust volumetric flow rate of 518 ACFM.

Predicted ambient impacts, including the DEQ-approved ambient background concentration, slightly exceeded the allowable 1-hour SO_2 NAAQS for Case 1. The predicted impact, plus background, for Case 2, demonstrated compliance with the 1-hour SO_2 NAAQS with a comfortable margin. Sensitivity run results are listed in Table 17.

Design impacts for both cases were predicted to occur at the same receptor located within the 10-meter spacing refined grid, located approximately 20 meters from the ambient air boundary. The sensitivity analyses support the conclusion that when all four boilers are operating on biogas, 1-hour SO_2 NAAQS compliance is demonstrated at full load conditions but not at 75% load. Other load levels were not analyzed by DEQ. The SO_2 sensitivity analyses show that it is critical that boilers either operate only at loads very near 100% or that only 3 of the 4 boilers operate simultaneously.

Table 17. RESULTS FOR DEQ 1-HOUR AVERAGE NO_2 SENSITIVITY ANALYSES

Pollutant	Averaging Period	Operating Scenario	Modeled Design Value (µg/m³)[a]	Background Concentration (µg/m³)	Total Impact (µg/m³)	NAAQS[b] (µg/m³)	Percent of NAAQS
SO_2[c]	1-hour	Case 1: 4 Boilers at 75% Load	183.2[d]	16.7	199.9	196	102%
		Case 2: 3 Boilers at 75% Load	142.2[d]		158.9		81%

a. Micrograms per cubic meter.
b. National ambient air quality standards.
c. Sulfur dioxide.
d. Modeled design value is the maximum 5-year mean of 4th highest daily 1-hour maximum impacts for each year of a 5-year meteorological dataset.

5.0 Conclusions

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the City of Nampa WWTP facility will not cause or significantly contribute to a violation of any NAAQS and will not exceed allowable TAP increments.

References

1. *Policy on NAAQS Compliance Demonstration Requirements of IDAPA 58.01.01.203.02 and 403.02.* Idaho Department of Environmental Quality Policy Memorandum. Tiffany Floyd, Administrator, Air Quality Division, June 10, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *Ambient Ratio Method Version 2(ARM2) for use with AERMOD for1-hr NO_2 Modeling Development and Evaluation Report,* Prepared for American Petroleum Institute, 1220 L Street NW, Washington, DC 20005, by M. Podrez, RTP Environmental Associates, Inc., 2031 Broadway, Suite 2, Boulder, Colorado 80302, September 20, 2013.

4. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard,* R. Chris Owen and Roger Brode, Environmental Protection Agency, Office of Air Quality Planning and Standards, September 30, 2014.

5. *Modeling Compliance of the Federal 1-Hour NO_2 NAAQS,* Appendix C – In-Stack NO_2/NO_x Ratios, California Air Pollution Control Officers Association Engineering Managers, October 27, 2011.

6. *DEQ Guidance for Minor New Source Review Modeling of 1-Hour NO_2 from Intermittent Testing of Emergency Engines*, State of Idaho Department of Environmental Quality September 2013, Doc. I D AQ-011 (September 2013).

7. Google Earth and Google Earth Streetview. ©2018 Google LLC, used with permission. Google and the Google logo are registered trademarks of Google, LLC.

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on November 1, 2019:

Facility Comment: Permit Condition 1.4, Table 1.1 – Flare #2 currently has a model number of WG 244WS01912119S6 and an install date of 2010. The correct model number is 244WS and the installation date will be 2020.

DEQ Response: Permit Condition 1.4 has been updated with corrected model and installation date information for Flare #2.

Facility Comment: Permit Condition 2.19 – This condition currently states that the biogas flow rates associated with the flares and boilers should meet those outlined in Table 1.1. However, Stantec and the City request that PC 2.19 reference PC 2.9 rather than the Table 1.1 to maintain compliance with the overall combustion limit of 1,130,088 scf/day.

DEQ Response: Permit Condition 2.19 has been updated to include reference to Permit Condition 2.9, and the reference to Table 1.1 has been removed as requested.

APPENDIX D – PROCESSING FEE

PTC Processing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company: **Nampa WWTP**
Address: **340 West Railroad Street**
City: **Nampa**
State: **ID**
Zip Code: **83687**
Facility Contact: **Andy Zimmerman**
Title: **WWTP Superintendent**
AIRS No.: **027-00110**

N Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N

Y Did this permit require engineering analysis? Y/N

N Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_x	-13.5	0	-13.5
SO_2	-10.3	0	-10.3
CO	19.0	0	19.0
PM10	0.6	0	0.6
VOC	4.0	0	4.0
Total:	-0.2	0	**-0.2**
Fee Due	**$ 1,000.00**		

Comments: