Appendix G: Air Quality Construction Permit Application

Application for Air Quality Construction Permit

Otter Tail Power Company

Astoria Station

near Astoria, South Dakota

Submitted to:

South Dakota Department of Environment and Natural Resources

Air Quality Program

523 East Capitol

Pierre, South Dakota 57501-3181

Prepared by:

HDR

701 Xenia Ave. South, Suite 600

Minneapolis, MN 55416

September 2017

Contents

Tables

Figures

Appendices

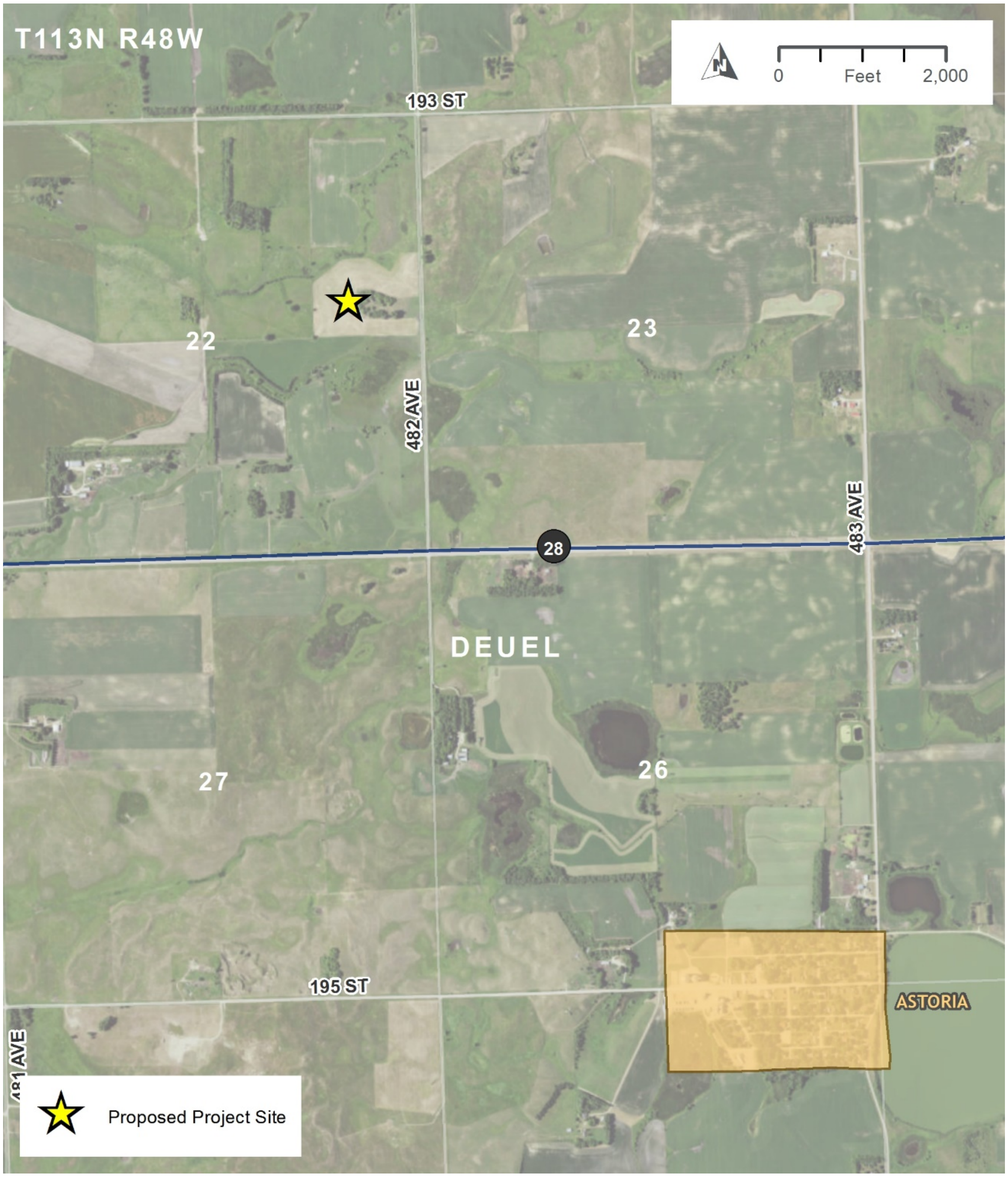
1.0 Introduction

Otter Tail Power Company (OTP) proposes to construct an electric generating facility 1.5 miles northwest of Astoria, in Deuel County, South Dakota. The approximate 250 megawatt (MW) facility would generate power with a single simple-cycle combustion turbine fired exclusively on pipeline natural gas. The plant would be a peaking facility to serve periods of high demand or periods when other generating resources, including renewables, are not available. The general site location is shown in Figure 1, and Figure 2 shows a closer view of the proposed facility location.

Figure 1. General Location of Proposed OTP Astoria Generating Facility

OTTER TAIL POWER COMPANY

Figure 2. Site Location of Proposed OTP Astoria Generating Facility



2.0 Project Description

2.1 Emission Units

The primary emission unit at the facility would be an approximate 250 MW combustion turbine generator. OTP is considering multiple potential vendors for this unit, so exact power output and heat input specifications are not yet available. However, this permit application presents data reflecting the upper range of expected heat input capacities and outputs for the annual average ambient conditions at the site, including elevation and ambient air temperature. Because combustion turbines can produce more power at low ambient air temperatures, winter time maximum electrical power output could be higher than 250 MW.

Smaller emission units would support operation of the generating facility. A natural gas fired dewpoint heater would be used to heat the incoming natural gas. This type of heating helps to ensure that any heavier hydrocarbon compounds in the natural gas stream are not in a liquid aerosol state as they enter the combustion turbine; this helps prevent wear and damage to the turbine. The dewpoint heater would use a water and glycol bath that would be kept warm via natural gas fired burners. The natural gas for turbine fuel would be pulled from the pipeline and passed through a heat exchanger in the water bath section of the dewpoint heater before the natural gas is routed to the turbine.

In addition, a diesel-powered fire pump engine would be included to support facility safety. The fire pump engine would be used for its designed purpose only in an emergency. However, to help ensure that the fire pump engine is ready for any emergency needs due to a fire, it would be required to be exercised periodically to demonstrate its readiness for operation, and to maintain moving parts in a lubricated state. The fire pump engine would be expected to run less than 100 hours per year, but the emission calculations are conservatively based on 500 hours per year.

South Dakota Department of Environment and Natural Resources (DENR) permit application forms with additional technical information are provided in Appendix A of this application.

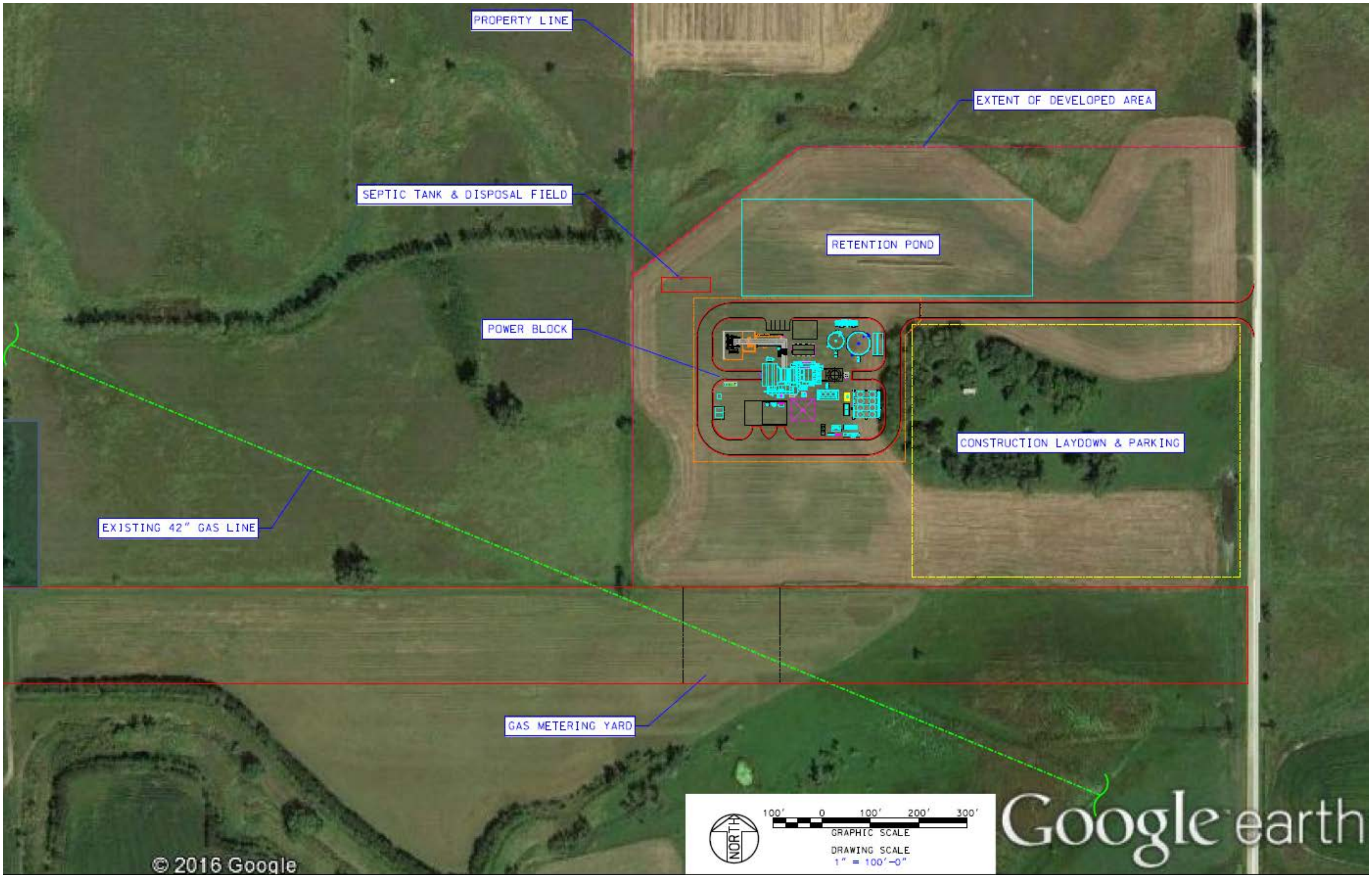
2.2 Site Layout

No detailed design has been conducted at this time, but a preliminary site and plot plan have been prepared for OTP by an engineering contractor, Sargent and Lundy, as shown in Figure 3. A preliminary general arrangement drawing is provided in Appendix C. These figures show tentative equipment layout on the site, including the locations of the emission units, but the equipment arrangement could change pending completion of final design.

2.3 Emission Controls

Given the clean fuels proposed for the emission units, post-combustion emission controls would not be needed to maintain levels of emissions in compliance with the proposed Prevention of Significant Deterioration (PSD) minor source status, and to meet applicable emissions standards (see Section 3 for further discussion). The combustion turbine would be designed with a dry-low-nitrogen-oxide (NOx) combustor, the dewpoint heater would be designed with low-NOx burners, and the fire pump would be designed and certified by the manufacturer to meet the applicable Tier 3 emissions standards (see Section 3.3.3).

Figure 3. Preliminary Layout of Power Block on Aerial Image



Source: Sargent and Lundy

3.0 Estimated Emissions and Applicable Regulations

3.1 Emission Factors

Emission factors for criteria air pollutants from the combustion turbine were obtained from emission estimates supplied by prospective equipment vendors. As of the filing of this application, OTP has not selected a combustion turbine vendor. As such, the emission rates included in this permit application account for the variability in emissions associated with technology offerings from potential turbine vendors. All other emission factors for the combustion turbine and all emission factors for the other emission sources, including some greenhouse gases (GHGs) and hazardous air pollutant (HAP) emission factors, were obtained from various sections of the United States Environmental Protection Agency's (EPA's) Compilation of Air Pollution Emission Factors (AP-42), EPA rules, or mass balance calculations (for sulfur compounds).

3.2 Emission Estimates and Prevention of Significant Deterioration Applicability

This section of the permit application provides estimated emissions of air pollutants and a comparison with thresholds that would define the facility as a major source under PSD permitting rules. OTP proposes to limit the facility operation such that total facility emissions of any applicable pollutant would not exceed the PSD major source threshold of 250 tons per year. OTP proposes to track emissions of NO_x and carbon monoxide (CO) from the combustion turbine on a 12-month rolling sum basis to ensure that the facility does not emit at major source levels, and would therefore be classified as a minor source under PSD rules.

The equipment proposed for installation at the Astoria Station would emit:

- CO
- NO_x
- Filterable particulate matter (PM)
- Particulate matter less than 10 microns and less than 2.5 microns in diameter (PM_{10} and $PM_{2.5}$, respectively)
- Sulfur dioxide (SO_2)
- Volatile organic compounds (VOCs)
- Sulfuric acid (H_2SO_4)
- Lead (Pb)
- GHGs, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O)
- HAPs regulated under the Clean Air Act (CAA) and 40 Code of Federal Regulations (CFR) 63

Annual potential-to-emit (PTE) calculations for the combustion turbine are representative of worst-case emissions for prospective vendors, and include emissions due to the startup and shutdown conditions, which tend to increase emissions of NO_x, CO, and VOCs. The only fuel for the combustion turbines would be pipeline natural gas. Emissions calculations included in Appendix C are based on a fuel sulfur level of 0.5 grains per 100 standard cubic feet (scf) in the pipeline natural gas. This upper bound to the sulfur level is consistent with the definition of pipeline natural gas as provided in the Acid Rain rules (40 CFR 72.2).

The dewpoint heater would be fired only with pipeline natural gas. The fire pump engine would be fired only with ultra-low sulfur diesel (ULSD) fuel. ULSD fuel has a maximum allowed sulfur content of 15 parts per million (ppm) by weight (in accordance with 40 CFR 80), so this value is used for calculating emissions from this reciprocating internal combustion engine (RICE). Consistent with EPA assumptions for emergency engines, the annual PTE for the fire pump would be based on a conservatively high 500 hours of operation per year.

GHG emissions from the proposed project are based on the summed estimates of emissions for each individual GHG, including CO_2, CH_4, and N_2O. The global warming potential (GWP) values provided in 40 CFR 98 were used to convert estimated emissions of each GHG into estimated CO_2 equivalents (CO_2e).

Insignificant emission sources would include a small ULSD fuel tank for the fire pump engine, with negligible evaporative VOC emissions. These emissions would not affect VOCs in terms of potentially exceeding or avoiding the triggering of PSD review for the pollutant. Given the very low level of emissions expected (less than 1 pound per year, based on similar projects) from this small tank of low volatility fuel, such emissions are not estimated in this document.

Emissions of NO_x and CO have the greatest potential to trigger PSD major source status. OTP would install continuous emission monitoring systems (CEMS) for these pollutants on the combustion turbine stack to demonstrate that total facility emissions do not exceed the 250 tons per year PSD major threshold for any 12-month rolling period.

Calculated PTE levels for the project are summarized in Table 1 in comparison to PSD major source and HAP major source thresholds. These values represent the highest emission values calculated for the three prospective combustion turbine models that were evaluated, considering that NO_x and CO emissions would be continuously measured from the turbines and tallied monthly to ensure that the 12-month rolling sum of emissions of these pollutants for the facility as a whole do not exceed 249 tons per year (allowing a margin with respect to the 250 tons per year major threshold). To accomplish this, OTP proposes to limit the turbine emissions alone to no more than 247 tons per year of NO_x and 246 tons per year of CO, allowing for maximum potential emissions from the smaller emission units to maintain facility emissions of less than 249 tons per any 12-month period.

Emissions of the dewpoint heater are based on a 4,000 hours per year maximum operating assumption, and emissions of the fire pump engine are based on a 500 hours per year maximum operating assumption. Spreadsheets showing the emission calculations for each emission unit and the facility as a whole are provided in Appendix B.

Table-1: Maximum Potential Emissions and PSD/BACT Applicability

Pollutant	Potential or Limited Emissions (tons per year)	Major Source Threshold (tons per year)	PSD/BACT Applicability (yes/no)
Nitrogen oxides (NO_x)	248.7	250	No
Carbon monoxide (CO)	248.8	250	No
Particulate matter (PM)	9.0	250	No
PM_{10}	20.7	250	No
$PM_{2.5}$	20.7	250	No
Sulfur dioxide (SO_2)	6.3	250	No
Volatile organic compounds (VOCs)	64.4	250	No
Lead (Pb)	Negligible	250	No
Sulfuric acid (H_2SO_4)	0.8	250	No
Total Fluorides	Negligible	250	No
Carbon dioxide equivalents (CO_2e)	550,694	NA	NA

PSD = Prevention of Significant Deterioration; BACT = Best Available Control Technology; NA = not applicable; PM_{10} = Particulate matter less than 10 microns in diameter; $PM_{2.5}$ = Particulate matter less than 2.5 microns in diameter

3.3 New Source Performance Standards

The 2014 and earlier federal New Source Performance Standards (NSPS) found in 40 CFR 60 have been incorporated by reference into South Dakota Rules, Chapter 74:36:07. These include the federal NSPS Subpart KKKK, applicable to the proposed combustion turbine; Subpart IIII, applicable to the proposed fire pump; and Subpart Dc, applicable to the proposed dewpoint heater.

A newer federal NSPS for GHGs, under Subpart TTTT, is not yet included in South Dakota Rules, but unless EPA suspends or modifies the rule, it will apply to the proposed combustion turbine. The NSPS-affected emission units are listed in the following sections, with reference to the applicable South Dakota Rules and/or 40 CFR 60 Subpart designations. In addition to the specific requirements under each type of emission unit, all NSPS-affected units must meet applicable General Provisions under 40 CFR 60, Subpart A, including notification, testing, recordkeeping, and reporting requirements.

3.3.1 Combustion Turbines (40 CFR 60, Subpart KKKK)

Subpart KKKK applies to combustion turbines constructed, modified, or reconstructed after February 18, 2005. Units subject to Subpart KKKK are exempt from the older NSPS for combustion turbines under 40 CFR 60, Subpart GG, as explicitly stated in Subpart KKKK, under 40 CFR 60.4305.

The NSPS limits from Subpart KKKK for combustion turbines are summarized in Table 2. The heat input ranges in this table are for each individual combustion turbine, rather than a facility or modification as a whole. The maximum heat input for the combustion turbine proposed for this project would be in excess of 850 million British thermal units per hour (MMBtu/hr).

The limit in Table 2 for SO_2 would be met by burning pipeline natural gas. Typical pipeline natural gas has an emission rate approximately two orders of magnitude lower than the limit shown in Table 2.

Table 2: Emission Limits for Natural Gas-Fired Combustion Turbines (40 CFR 60, Subpart KKKK)

Pollutant	Combustion Turbine Peak Heat Input (HHV), Output, and Operating Conditions	Emission Limit
NO_x (as NO_2)	Greater than 850 MMBtu/hr maximum heat input rating, operating at 75% load or greater and at over 0 degrees Fahrenheit (°F) ambient temperature	15 ppm at 15 percent O_2 or 0.43 lb/MWh
	Greater than 30 megawatt maximum rated output and operating at less than 75% load or at less than 0°F ambient temperature	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh)
SO_2	All stationary combustion turbines in lower 48 states	0.90 lb/MWh or 0.060 lb/MMBtu

HHV = higher heating value; NOx = nitrogen oxides; NO_2 = nitrogen dioxide; MMBtu/hr = million Btu per hour; ppm = parts per million; O_2 = oxygen; lb/MWh = pounds per megawatt-hour; ng/J = nanograms per joule; SO_2 = sulfur dioxide

In addition to the previously listed emission standards, EPA published (Federal Register, August 29, 2012) a proposed rule to amend Subpart KKKK. The proposed rule would apply the limits in Table 2 (or approximately equivalent alternative limits on a pounds per MMBtu basis) to not only normal load operations, but would include startup, shutdown, and malfunction (SSM) conditions in the limitations. The proposed revisions to include SSM conditions would apply to combustion turbines constructed, modified, or reconstructed after August 29, 2012. Under the proposed rule, the averaging periods for the limits are 4 hours for simple cycle units and 30 days for combined-cycle units. If this rule is finalized as proposed, it could present a significant challenge for simple cycle units that barely meet 15 ppm of NO_x for routine operation (that is, without considering SSM operations). However, the low load (under 75 percent) limit for NO_x may provide sufficient flexibility to accommodate normal startup and shutdown operations, apart from malfunctions.

3.3.2 Dewpoint Heater (Subpart Dc)

Because the proposed dewpoint heater would be constructed after June 9, 1989, would have a maximum design heat input capacity between 10 and 100 MMBtu/hr (approximately 15 MMBtu/hr, HHV), and would meet the definition of a steam generating unit under Subpart Dc, the dewpoint heater would be subject to 40 CFR 60, Subpart Dc. Note that steam generating unit as defined in Subpart Dc means "a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium." Because the dewpoint heater would combust only natural gas fuel, none of the Subpart Dc emissions standards would apply to the unit. The only requirements applicable to this unit under 40 CFR 60, Subpart Dc are to submit an initial notification under 40 CFR 60.48c(a) and to keep either daily or monthly records of the amount of natural gas combusted in the unit according to 40 CFR 60.48c(g).

3.3.3 Fire Pump Engine (40 CFR 60, Subpart IIII)

The federal NSPS for compression ignition engines, under Subpart IIII, would apply to the proposed fire pump engine. This unit would be certified by the manufacturer to meet the emission requirements of Subpart IIII as they apply to fire pump engines. Subpart IIII requires that an owner or operator of an emergency stationary compression-ignition internal combustion engine that does not meet the standards applicable to non-emergency engines (OTP does not expect that the engine would meet non-emergency engine standards) install a non-resettable hour meter prior to commencing operation of the engine. The fire pump would meet Tier 3 emissions standards as required under Subpart IIII, which references the emissions standards listed in 40 CFR 89.

3.3.4 Electric Generating Unit Greenhouse Gas New Source Performance Standards (40 CFR 60, Subpart TTTT)

On October 23, 2015, EPA published in the Federal Register a final NSPS for new fossil fuel fired electric generating units (EGUs), under 40 CFR 60, Subpart TTTT. While this rule is currently under litigation, it remains in effect. A new EGU that is subject to this rule includes any steam electric generating unit, integrated gasification combined-cycle unit, or stationary combustion turbine that commenced construction after January 8, 2014, which has more than 250 MMBtu/hr heat input of fossil fuels alone or in combination with other fuels, and which serves a generator capable of selling more than 25 MW of electricity to a utility power distribution system.

Combustion turbines are subject to the CO_2 emission rate limits in Table 2 of Subpart TTTT. For combustion turbines that essentially supply baseload or intermediate load electrical demand, the Subpart TTTT CO_2 limitation is 1,000 pounds of CO_2 per megawatt-hour (MWh) of gross energy output. For combustion turbines, this generally requires a combined-cycle unit to attain the standard. For peaking combustion turbines fired mainly on natural gas (for at least 90 percent of 12-month rolling average heat input), the CO_2 limitation is 120 pounds of CO_2 per MMBtu of heat input (higher heating value basis).

The less stringent heat input based standard requires that such stationary combustion turbines supply no more than their design efficiency or 50 percent, whichever is less, times their potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis. For the simple-cycle turbines being considered for the proposed project, this limitation equates to an annual capacity factor of between 35 percent and 38 percent, or somewhere in the range of approximately 3,100 to 3,300 hours per year of equivalent full-load operation. Thus, for example, a combustion turbine operating 4,000 hours per year would have to meet the 1,000 pounds of CO_2 per MWh standard, meaning it would need to be a combined-cycle unit.

The proposed combustion turbine would demonstrate compliance with the 120 pounds of CO_2 per MMBtu limit by tracking heat input, natural gas use, and related CO_2 emissions, and using these data to calculate pounds of CO_2 per MMBtu of heat input.

3.4 National Emissions Standards for Hazardous Air Pollutants

National Emissions Standards for Hazardous Air Pollutants (NESHAPs) applicable to the proposed project are published under 40 CFR 63. This summary of NESHAP requirements is based on the facility being a minor source of HAPs as demonstrated in the PTE calculations for this project. A minor source of HAPs is a facility with a PTE of less than 10 tons per year of a single HAP and less than 25 tons per year of all HAPs combined.

The potential applicability of NESHAPS is discussed in the following sections.

3.4.1 Stationary Combustion Turbines (40 CFR 63, Subpart YYYY)

Subpart YYYY of 40 CFR 63 is the NESHAP for stationary combustion turbines, existing, new, or reconstructed, located at a major source of HAPs. Because the facility would be a minor source of HAPS, Subpart YYYY would not apply to the proposed combustion turbine.

3.4.2 Reciprocating Internal Combustion Engines (40 CFR 63, Subpart ZZZZ)

The NESHAP for RICE units (40 CFR 63, Subpart ZZZZ) provides separate requirements for new RICE units, depending on whether they are located at a major or an area (minor) source of HAPs. Given the minor source status of the site for HAP emissions, the RICE Maximum Achievable Control Technology (MACT) requirements for the diesel powered fire pump would be met by meeting the NSPS under 40 CFR 60, Subpart IIII. No further requirements of the NESHAPS would apply to the fire pump, as stated under section 63.6590(c)(1).

3.4.3 Industrial, Commercial, and Institutional Boilers Area Sources (40 CFR 63, Subpart JJJJJJ)

The proposed dewpoint heater is a boiler under the definition of boiler for purposes of the NSPS under Subpart Dc. However, the definition of boiler under the NESHAPS Subpart JJJJJJ is different, and states:

> Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler. (40 CFR 63 Subpart JJJJJJ)

Further, the rule defines process heater as:

> Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating. (40 CFR 63 Subpart JJJJJJ)

The dewpoint heater appears to meet the definition of a process heater. Because process heaters are excluded from the definition of boiler under Subpart JJJJJJ, the dewpoint heater would not be subject to Subpart JJJJJJ. Note that even if this exclusion did not apply (that is, if the dewpoint heater was determined to be a boiler for Subpart JJJJJJ purposes), the applicability section under Subpart JJJJJJ exempts gas-fired boilers from the rule. Therefore, no NESHAPS requirements would apply to the dewpoint heater.

3.5 Acid Rain

The proposed combustion turbine would be an affected unit for purposes of the Acid Rain rules (40 CFR 72–76) because it is a fossil fuel fired utility unit that would generate more than 25 MW of electricity. In general, the Acid Rain rules require a facility to hold emission allowances for SO_2 and NO_x emissions and to monitor opacity; SO_2, NO_x, and CO_2 emissions; and flow rate or heat input (as applicable) for each affected unit.

OTP would implement either the applicable monitoring requirements of 40 CFR 75.11 (SO_2), 75.12 (NO_x), and 75.13 (CO_2), or the alternate methods detailed in Appendix D (SO_2), Appendix E (NO_x), and Appendix G (CO_2) of 40 CFR 75 for purposes of Acid Rain emissions monitoring. Because the combustion turbine would combust only pipeline natural gas, the unit would be exempt from the opacity monitoring requirements in accordance with 40 CFR 75.14. An Acid Rain permit application must be submitted to EPA at least 24 months before this affected unit (the combustion turbine) begins operation.

3.6 Ambient Air Quality Standards

This application for a minor permit does not require that the proposed facility demonstrate compliance (via dispersion modeling) with National Ambient Air Quality Standards (NAAQS) provided in 40 CFR 50, which are incorporated by reference in South Dakota Rules. However, given the relatively low emissions associated with firing pipeline natural gas, and the small fire pump that would burn ULSD fuel, the facility is not expected to threaten attainment of NAAQS in the project area.

3.7 Cross-State Air Pollution Rule

Starting in 2015, EGUs in most states in the eastern half of the nation, including some Great Plains states, must collectively, in each state, meet emissions budgets for SO_2 and NO_x under the federal Cross-State Air Pollution Rule (CSAPR). However, South Dakota was exempted by EPA from the CSAPR program, given the state’s minimal modeled contribution to other downwind states’ ozone and fine particulate matter concentrations. Therefore, CSAPR requirements do not apply to the proposed project.