ALASKA
PipelineProject

Draft Resource Report 9 – Rev 0
Air and Noise Quality

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TransCanada ExxonMobil

DRAFT

Notes:

Yellow highlighting is used throughout this draft Resource Report to highlight selected information that is pending or subject to change in the final report.

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ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
§	Section
μg/m^3	microgram per cubic meter
AAAQS	Alaska Ambient Air Quality Standards
AAC	Alaska Administrative Code
ACRC	Alaska Climate Research Center
ADEC	Alaska Department of Environmental Conservation
ADOTPF	Alaska Department of Transportation and Public Facilities
APP	Alaska Pipeline Project
ASOS	Automated Surface Observation System
BACT	Best Available Control Technology
BOEM	Bureau of Ocean Energy Management
CAA	Clean Air Act
CEQ	Council on Environmental Quality
C.F.R.	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COOP	volunteer-based meteorological station
dBA	decibels of A-weighted scale
DOE	U.S. Department of Energy
DOI	Department of the Interior
DOS	Department of State
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FAA	U.S. Federal Aviation Administration
FERC	U.S. Federal Energy Regulatory Commission
FWS	U.S. Fish and Wildlife Service
GHG	greenhouse gas
GTP	Gas Treatment Plant
GWP	global warming potential
HAP	hazardous air pollutant
HDD	horizontal directional drill
in.	inch
IPCC	Intergovernmental Panel on Climate Change
L_{dn}	day-night sound level
$L_{eq(24)}$	24-hour equivalent sound level
L_n	night sound level
MACT	maximum achievable control technology
mg/m^3	milligram per cubic meter
MMBtu	million British thermal units
MP	milepost

mph	miles per hour
N/A	not applicable
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NCDC	National Climate Data Center
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NNSR	nonattainment New Source Review
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSA	noise-sensitive area
NSPS	new source performance standard
NSR	New Source Review
O_3	ozone
PBU	Prudhoe Bay Unit
PM_{10}	particulate with aerodynamic diameter of 10 microns or less
$PM_{2.5}$	particulate with aerodynamic diameter of 2.5 microns or less
ppbv	parts per billion by volume
ppmv	parts per million by volume
PSD	Prevention of Significant Deterioration
pt.	part
PT Pipeline	Point Thomson Gas Transmission Pipeline
PTU	Point Thomson Unit
SIP	state implementation plan
SO_2	sulfur dioxide
TBD	to be determined
tpy	tons per year
VOC	volatile organic compound
WRCC	Western Regional Climate Center

9.0 RESOURCE REPORT 9 – AIR AND NOISE QUALITY

The location information, facility descriptions, resource data, construction methods, and mitigation measures presented in this report are preliminary and subject to change. APP is conducting engineering studies, environmental resource surveys, agency consultations, and stakeholder outreach efforts to further refine and define the details of the Project.

The Project described in this resource report is being designed and developed based on estimated volumes of natural gas from projected shipper commitments. If final shipper commitments are significantly different from those estimated, the Project may be adjusted accordingly.

9.1 INTRODUCTION

TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd., working with ExxonMobil Alaska Midstream Gas Investments LLC, are developing a joint project to treat, transport, and deliver natural gas from the Alaska North Slope (ANS) to pipeline facilities in Alberta, Canada for markets in the contiguous United States and North America. This joint project is referred to as the Alaska Pipeline Project (APP or Project)[1].

As required by Title 18 Code of Federal Regulations (C.F.R.) Section (§) 380.12 and consistent with the Alaska Natural Gas Pipeline Act of 2004 (ANGPA), APP has prepared this draft resource report in support of its application to the U.S. Federal Energy Regulatory Commission (FERC) for a Certificate of Public Convenience and Necessity (CPCN) under Section 7(c) of the Natural Gas Act (NGA) to construct, own, and operate the portion of the Project in Alaska. This draft resource report pertains only to that portion of the Project in Alaska, and unless the context otherwise requires, references in this draft resource report to APP refer only to the Alaska portion of the Project[2].

As shown in Figure 1.1-1 of Resource Report 1, APP will comprise the following major components[3,4]:

- The Point Thomson Gas Transmission Pipeline (PT Pipeline)[5], consisting of approximately 58.4 miles of buried 32-inch-diameter pipeline from the Point Thomson Unit (PTU) to an APP Gas Treatment Plant (GTP) and associated facilities near Prudhoe Bay;

1 Depending on the context, the term APP refers to the joint project or, collectively, to the sponsoring entities.

2 The Canadian Section refers to the portion of the Project from the Yukon border to the pipeline facilities in Alberta, Canada.

3 In previous FERC filings, the Point Thomson Gas Transmission Pipeline was referred to as Zone 1, the Gas Treatment Plant was referred to as Zone 2, and the Alaska Mainline was referred to as Zone 3 of the Alaska-Canada Pipeline.

4 As part of the Project, APP proposes to construct compressor stations, meter stations, various mainline block valves, pig launcher and receiver facilities, as well as associated ancillary and auxiliary infrastructure, including additional temporary workspace, access roads, helipads, construction camps, pipe storage areas, contractor yards, borrow sites, and dock modifications at Prudhoe Bay.

5 The origin of the PT Pipeline is assumed to be located at an outlet from the PTU. The final length may vary depending on the final gas development plan for the PTU.

- The GTP, which will have the capacity to process gas received from the PTU and the existing Central Gas Facility (CGF) on the Prudhoe Bay Unit (PBU) in order to deliver an annual average capacity up to 4.5 billion standard cubic feet per day (bscfd) (standard conditions: 14.73 pounds per square inch absolute and 60º Fahrenheit) of sales quality gas; and
- The Alaska Mainline, consisting of approximately 745.1 miles of 48-inch-diameter pipeline, all of which is buried except as otherwise described in this Resource Report. The Alaska Mainline extends from the GTP to the Alaska-Yukon border east of Tok, Alaska, and includes provisions for intermediate gas delivery points within Alaska.

Table 9.1-1 lists the FERC's filing requirements and additional information applicable to Resource Report 9 taken from FERC's Guidance Manual for Environmental Report Preparation:

TABLE 9.1-1

Alaska Pipeline Project
Resource Report 9 Filing Requirements Checklist

Requirement	Where Found In Document
FERC REQUIREMENTS FROM 18 C.F.R. § 380.12	
1. Describe existing air quality in the vicinity of the project. .(§380.12[k][1]) • Identify criteria pollutants that may be emitted above U.S. Environmental Protection Agency (EPA)-identified significance levels	Sections 9.2.1, 9.2.2, and 9.2.3
2. Quantify the existing noise levels (day-night sound level [L_{dn}] and other applicable noise parameters) at noise-sensitive areas (NSAs) and at other areas covered by relevant state and local noise ordinances. (§ 380.12[k][2])	Sections 9.4.1 and 9.4.2
• If new compressor station sites are proposed, measure or estimate the existing ambient sound environment based on current land uses and activities. • For existing compressor stations (operated at full load), include the results of a sound level survey at the site property line and nearby noise-sensitive areas. • Include a plot plan that identifies the locations and duration of noise measurements. • All surveys must identify the time of day, weather conditions, wind speed and direction, engine load, and other noise sources present during each measurement.	N/A
3. Quantify existing and proposed emission of compressor equipment, plus construction emissions, including nitrogen oxides (NO_x) and carbon monoxide (CO), and the basis for these calculations. Summarize anticipated air quality impacts for the project. (§ 380.12[k][3]) • Provide the emission rate of NO_x from existing and proposed facilities, expressed in pounds per hour and tons per year for maximum operating conditions, include supporting calculations, emission factors, fuel consumption rate, and annual hours of operation.	Sections 9.2.4, 9.2.5, and Appendix 9A
4. Describe the existing compressor units at each station where new, additional, or modified compressor units are proposed, including the manufacturer, model number, and horsepower of the compressor units. For proposed new, additional, or modified compressor units include horsepower, type, and energy source.(§ 380.12[k][4])	Section 9.2.4.1
5. Identify any nearby NSAs by distance and direction from the proposed compressor unit building/enclosure. (§ 380.12[k][4])	Section 9.4.2.2
6. Identify any applicable state or local noise regulations. (§ 380.12[k][4]) • Specify how the facility will meet the regulations.	Sections 9.4.1.2 and 9.4.1.3
7. Calculate the noise impact at NSAs of the proposed compressor unit modifications or additions, specifying how the impact was calculated, including manufacturer's data and proposed noise control equipment. (§ 380.12[k][4])	Section 9.4.2.2
OTHER INFORMATION OFTEN MISSING AND RESULTING IN DATA REQUESTS PER FERC'S GUIDANCE MANUAL FOR ENVIRONMENTAL REPORT PREPARATION	
• Provide copies of application for state air permits and agency determinations, as appropriate.	See Section 1.11 of Resource Report 1

TABLE 9.1-1

Alaska Pipeline Project
Resource Report 9 Filing Requirements Checklist

Requirement	Where Found In Document
• For major sources of air emissions (as defined by the EPA), provide copies of applications for permits to construct (and operate, if applicable) or for applicability determinations under regulations for the prevention of significant air quality deterioration and subsequent determinations.	See Section 1.11 of Resource Report 1
• Describe measures and manufacturer's specifications for equipment proposed to mitigate impact to air and noise quality, including emission control systems, installation of filters, mufflers, or insulation of piping and building, and orientation of equipment away from NSAs.	TBD

Values specified as To Be Determined (TBD) will be updated for the final report.

Mileposts (MPs) are commonly used markers along linear projects, such as APP. Where necessary to distinguish the PT Pipeline from the Alaska Mainline, APP has prefixed its MP identifier with a PT Pipeline MP (PMP) or an Alaska Mainline MP (AMP). This convention is used in APP's application and supporting maps and alignment sheets (refer to Appendix 1O of Resource Report 1) to identify resources and features along the respective pipeline routes.

The purpose of Resource Report 9 is to describe the existing air quality and noise environment and to assess the potential for air quality and noise impacts by the Project (construction and operation) on the surrounding environment.

9.2 METEOROLOGY AND AIR QUALITY

This section describes the area's meteorology and assesses the potential air quality impacts of APP (construction and operation) on the surrounding environment.

9.2.1 REGIONAL CLIMATE

9.2.1.1 Introduction

Alaska's diverse climate is characterized by widely varying temperature ranges and variable weather phenomena due to the state's enormous size, highly variable topographical features, and location in the high latitudes. The climate and meteorology in localized areas along the pipeline route will influence the design and operation of Project facilities. Meteorology also will play an important role in determining the direction of atmospheric transport and the degree of dispersion of air pollutants emitted from emission sources associated with the Project construction and operation.

9.2.1.2 Topographic Features and Elevation

The largest mountain ranges within Alaska are the Brooks Range, which separates the Arctic region from Interior Alaska, and the Alaska-Aleutian Range, which extends westward along the Alaska Peninsula, northward about 200 miles from the Peninsula, and eastward to Canada. Numerous mountain peaks within the state have elevations that exceed 10,000 feet; however, nearly all of the inhabited sections of the state are at elevations of 1,000 feet or less (Western Regional Climate Center [WRCC] 2011).

9.2.1.3 Climatic Zones

The geographical landscapes mentioned above have a significant effect on Alaska's climate. Alaska's climate falls into three major climatic zones: Arctic, Continental, and Maritime. Figure 9.2.1-1 shows the principal climatic zones and topography of Alaska. As noted by the WRCC, the number of discrete zones has sometimes been expanded to include smaller, transitional regions between Maritime and Continental zones, the first encompassing the western portions of Bristol Bay and west-central Alaska, and the second covering the southern portion of the Copper River Basin, Cook Inlet, and the northern extremes of the south coast.

Climate in a significant portion of Alaska is influenced by ocean waters and the seasonal distribution of sea ice. Locations that are under the predominant influence of the sea are characterized by relatively small seasonal temperature variability and high humidity. Conversely, locations that are inland and cut off from the moderating influence of the ocean experience a continental climate that is characterized by large daily and annual temperature ranges, low humidity, and relatively light and irregular precipitation (Alaska Climate Research Center [ACRC] 2011).

Elevation above sea level is another important factor that influences local climate in Alaska and accounts for much of its variability. Lower elevations in the Interior, such as the Yukon Flats and the Tanana Valley, experience extreme cold in the winter and high summertime temperatures. Additionally, temperature inversions are frequent in winter, wherein the lower atmosphere layer becomes thermally separated from the air above it, a condition which can trap fog or concentrate airborne pollutants closer to the ground surface. This generally occurs under clear skies when winds are light and stable and surface temperatures are low (WRCC 2011).

9.2.1.4 Meteorological Stations Network

A number of weather stations are maintained in the Project area, and provide data that is useful for characterizing the weather conditions that will be experienced during Project construction and operation. Table 9.2.1-1 lists the stations that have been identified and Figure 9.2.1-2 shows their locations. Information regarding these stations has been obtained from several climate agencies, including the National Climatic Data Center (NCDC), the ACRC, and the WRCC. Climate statistics for a number of such stations within the general Project vicinity[6] are presented in Table 9.2.1-2.

6 The terms "Project area" and "Project footprint" are defined to include the project facilities and land requirements for construction and operation. The term "Project vicinity" is used to mean the area or region near or surrounding the Project area, and is subject to the context in which the term is used.

Figure 9.2.1-1
Climatic Zones and Topography of Alaska

Source: ACRC 2011

TABLE 9.2.1-1

Alaska Pipeline Project
Description of Meteorological Measurement Stations within the Project Vicinity

Station Name	Station Type	Years active	North Latitude	West Longitude	Elevation (feet)	Information Source
Deadhorse Airport	Airways ASOS COOP	1969-present	70º195'	148º465'	61	ACRC/NCDC
Happy Valley Camp	COOP	1970-present	69º167'	148º833'	948	NCDC
Galbraith Lake Airport	Airways	1970-present	68º483'	149º483'	2,666	WRCC
Chandalar DOT	Airways COOP	2000-present	68º083'	149º567'	3,250	WRCC
Wiseman	COOP	1931-present	67º417'	150º1'	1,147	WRCC
Cold Foot WBAN 26467	Airways	1974-present	67º05'	149º567'	2,395	NCDC
Bettles Airport	Airways ASOS COOP	1951-present	66º917'	151º517'	642	ACRC/NCDC
Prospect Creek	Airways	1974-present	66º8'	150º633'	1,106	NCDC
Five Mile Camp	Airways	1970-present	66º083'	150º	440	WRCC
Fairbanks International Airport	ASOS COOP	1929-present	64º8'	147º883'	432	ACRC/NCDC
Big Delta Airport	Airways ASOS COOP	1937-present	64º	145º717'	1,268	ACRC/NCDC
Tok	Airways COOP	1934-present	63º35'	143º05'	1,620	ACRC/NCDC
Northway Airport	Airways ASOS COOP	1942-present	62º967'	141º933'	1,713	NCDC

Airways: Airport
ASOS - Automated Surface Observation System
COOP - Volunteer-based meteorological station

Figure 9.2.1-2
Meteorological Stations within the Project Vicinity

TABLE 9.2.1-2

Alaska Pipeline Project
Available Western Regional Climate Summaries for Stations along the Alaska Mainline and Point Thomson Gas Transmission Pipeline Routes

Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
DEADHORSE 1999-2010													
Average Max. Temperature (°F)	-8.9	-9.2	-11	9.6	26.1	46	53.6	49.1	40	22.8	6.7	-0.7	18.7
Average Min. Temperature (°F)	-22	-22	-24	-5.4	16.1	33	38.6	36.5	30	12.6	-6.2	-13.9	6.1
Average Total Precipitation (in.)	0.07	0.04	0.01	0.15	0.21	0.5	0.96	0.94	0.4	0.21	0.07	0.11	3.64
Average Total Snowfall (in.)							No Data						
Average Snow Depth (in.)							No Data						
GALBRAITH LAKE 1970-1980													
Average Max. Temperature (°F)	1.9	-3.7	2.9	18.7	41.6	56	61.2	59.2	40	15.6	10.4	-5.1	24.9
Average Min. Temperature (°F)	-18	-25	-21	-5.8	19.2	36	40.1	36.7	20	-3.1	-11	-24	3.5
Average Total Precipitation (in.)	0.68	0.26	0.39	0.12	0.36	1.4	0.93	1.6	0.7	1	0.5	0.51	8.46
Average Total Snowfall (in.)	8.5	2.9	6.8	1.4	0	0.7	0.5	0	4.6	9.2	6.6	5	46.1
Average Snow Depth (in.)	7	7	8	4	1	0	0	0	0	4	5	5	3
CHANDALAR ADOTPF 2000-2010													
Average Max. Temperature (°F)	1.4	4.3	5.9	23.7	41.3	57	57.2	52.6	39	20.2	8	6.5	26.4
Average Min. Temperature (°F)	-11	-8.6	-9.6	5.6	25	40	42	36.9	25	8.5	-3.4	-5.9	12
Average Total Precipitation (in.)	0.73	0.87	0.34	0.7	0.92	1.5	2.27	1.86	1.3	1.05	0.81	0.66	13.01
Average Total Snowfall (in.)	14	17.4	7.3	16.5	7.5	0.6	0	0	3.8	16.5	16.7	14.6	115
Average Snow Depth (in.)	23	32	36	41	23	0	0	0	0	7	15	21	16
WISEMAN 1949-2010													
Average Max. Temperature (°F)	-2.7	5.5	17.4	36.9	54.3	69	69.3	62.3	50	26.3	8.7	2.8	33.3
Average Min. Temperature (°F)	-21	-15	-12	10.1	28.9	43	45.3	39.2	30	9.5	-7.7	-15.2	11.2
Average Total Precipitation (in.)	0.75	0.64	0.28	0.6	1.04	1.7	2.46	2.19	1.7	0.71	0.8	0.74	13.63
Average Total Snowfall (in.)	15	11.2	4.5	5.4	0.7	0	0	0	3.4	9.7	11.9	11.8	73.6
Average Snow Depth (in.)	20	25	23	18	3	0	0	0	0	4	9	15	10
BETTLES FAA AIRPORT 1951-2010													
Average Max. Temperature (°F)	-4.3	1.9	14.6	32.8	53.5	68	69.4	62.5	49	25.6	6.1	-1.4	31.5
Average Min. Temperature (°F)	-20	-17	-9.1	10.3	33.6	47	48.9	43.4	32	12.5	-8	-16.6	13.1
Average Total Precipitation (in.)	0.8	0.77	0.63	0.61	0.7	1.4	2.04	2.48	1.8	1.12	0.93	0.87	14.11
Average Total Snowfall (in.)	11.7	11.2	9.6	7	1	0	0	0	2	11.7	14.1	15	83.2
Average Snow Depth (in.)	25	29	31	26	4	0	0	0	0	4	12	20	12
FIVE MILE 1970-1980													
Average Max. Temperature (°F)	-11	-2	17.2	36.2	58.9	70	74.4	70	51	26.2	6.7	-11.1	32.2
Average Min. Temperature (°F)	-27	-25	-11	8.4	32	43	44.5	39.1	28	9.4	-13	-27.5	8.4
Average Total Precipitation (in.)	0.28	0.22	0.35	0.21	0.67	1.4	1.25	1.08	0.9	1.01	0.87	0.65	8.93
Average Total Snowfall (in.)	4.5	2.5	5.5	2.1	0.1	0	0	0	0.1	10.5	7.9	6.8	40
Average Snow Depth (in.)	18	19	19	13	0	0	0	0	0	2	8	9	7
FAIRBANKS WSO AIRPORT 1949-2010													
Average Max. Temperature (°F)	-1.2	8.4	23.7	42.6	60.1	71	72.3	66.3	55	32.2	11.6	1.5	36.9

TABLE 9.2.1-2

Alaska Pipeline Project
Available Western Regional Climate Summaries for Stations along the Alaska Mainline and Point Thomson Gas Transmission Pipeline Routes

Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Average Min. Temperature (°F)	-19	-14	-3.2	20.3	37.9	49	52	46.8	36	17.3	-4.8	-15.3	16.9
Average Total Precipitation (in.)	0.58	0.42	0.35	0.29	0.58	1.3	1.97	1.85	1.1	0.77	0.67	0.68	10.56
Average Total Snowfall (in.)	10.5	8.3	6	3.1	0.7	0	0	0	1.3	10.4	12.7	12.2	65.1
Average Snow Depth (in.)	17	21	20	10	0	0	0	0	0	2	8	13	7
BIG DELTA FAA 1937-2010													
Average Max. Temperature (°F)	3.7	12.8	23.5	41	57.1	67	69.4	64.5	53	31.9	13.9	5.5	36.9
Average Min. Temperature (°F)	-11	-4.3	1.8	20.8	37.2	48	50.7	45.8	36	18.5	0.1	-8.6	19.5
Average Total Precipitation (in.)	0.31	0.3	0.24	0.25	0.9	2.3	2.63	1.94	1.1	0.62	0.45	0.35	11.38
Average Total Snowfall (in.)	5.6	5.2	4.3	2.8	0.6	0	0	0	1.6	9.2	8.5	5.8	43.8
Average Snow Depth (in.)	8	10	9	4	0	0	0	0	0	2	5	6	4
TOK 1952-2010													
Average Max. Temperature (°F)	-6.3	7.5	24.8	44.2	60.5	71	73.1	68.2	54	31.5	8.7	-3.6	36.1
Average Min. Temperature (°F)	-25	-16	-6.1	15.9	29.7	40	43.6	39	29	12.8	-9.7	-21.4	11
Average Total Precipitation (in.)	0.37	0.25	0.18	0.17	0.7	2.3	2.09	1.3	0.9	0.55	0.49	0.45	9.65
Average Total Snowfall (in.)	4.9	3.5	2.7	2.3	0.7	0	0	0.2	1.5	7.2	6.8	5.8	35.6
Average Snow Depth (in.)	15	17	16	9	0	0	0	0	0	2	7	11	6
NORTHWAY FAA AIRPORT 1949-2010													
Average Max. Temperature (°F)	-9.8	3.2	22.7	41.9	56.9	67	69.5	64.9	52	29.5	5.5	-6.6	33.1
Average Min. Temperature (°F)	-27	-19	-8.7	15.1	32.9	44	48	42.8	31	13.2	-10	-22.4	11.7
Average Total Precipitation (in.)	0.27	0.23	0.18	0.21	0.94	2	2.57	1.44	1	0.51	0.34	0.28	9.94
Average Total Snowfall (in.)	5.4	4.6	3.4	2.2	0.8	0	0	0.2	1.1	6.9	6.4	5.9	36.8
Average Snow Depth (in.)	14	16	16	7	0	0	0	0	0	2	7	11	6

°F - degrees Fahrenheit
ADOTPF - Alaska Department of Transportation and Public Facilities
FAA - U.S. Federal Aviation Administration
in. - inches
Source: WRCC 2011

9.2.1.5 Summary of Climatological Tables

Based on the available data, the coldest locations in the Project area are on the North Slope at Prudhoe Bay and Deadhorse, and on the north side of the Brooks Range near Galbraith Lake. The warmest locations in the Project area are around the Fairbanks and Big Delta areas. Areas with the most snow (70 inches or more annually) are in the Brooks Range (Chandalar, Wiseman, and Bettles stations); however, Fairbanks receives 65 inches per year of snow on average. The coldest temperatures recorded in the Project area were in the -80s ºF at Prospect Creek on January 23, 1971. The Prospect Creek station also recorded the maximum annual snowfall in the Project area of over 163 inches in 1971. The warmest summer temperatures recorded in the Project area were at Fairbanks and Tok, which both reached 96 ºF on June 15, 1969 (WRCC).

The weather stations discussed above measure temperature and precipitation and in some cases may measure additional parameters. A summary of available information on these parameters is provided in Table 9.2.1-2 and below.

Relative Humidity

Humidity and dew point data are not available for many Alaska meteorological stations, however, the NCDC has reported average humidity for some areas along the route. The annual average relative humidity at the Fairbanks, Bettles, and Big Delta locations are all around 60 percent.

Wind

Except for localized strong wind conditions from passing storms, winds are generally light in the Interior, especially at lower elevations. More exposed North Slope locations experience much stronger wind speeds. Local wind flow patterns tend to be channeled or diverted by topographical features, such as mountain passes, valleys, and waterbodies. Winds in areas of extreme winter cold create a weather hazard to people exposed for even brief periods of time (WRCC 2011).

Wind speed data (speed and direction) are sparse at most of the stations within the Project vicinity, although winds are recorded at the Fairbanks, Big Delta, and Bettles stations. In Fairbanks, the highest wind speeds occur during the summer. The annual mean wind speed is 5.4 miles per hour (mph). The prevailing wind direction recorded at the Fairbanks Airport is from the north. Blizzard conditions are almost never seen, as winds in Fairbanks are above 20 mph less than one percent of the time.

In contrast to the Fairbanks wind monitor, surface winds at Big Delta have the strongest speeds in winter, and are lightest in summer. The direction, east-southeast, follows the orientation of the Tanana Valley from early fall to early spring, and follows the orientation of the Delta River (southwest) during the months of May through July. Wind speeds are high when compared with other Interior locations due to local strong pressure gradients. The annual mean wind speed at Big Delta is 8.2 mph. The Bettles monitor seldom sees strong winds during any season of the year or any significant directional variation from a prevailing northerly wind (WRCC 2011).

Clouds, Fog, and Visibility

Cloud cover and storm observations are also limited in the Project vicinity. For the Fairbanks, Big Delta, and Bettles monitoring stations, cloudy days occur for approximately 200 days of the year, while 90 days per year are partly cloudy, and about 70 days are clear (NCDC 2011). Fog typically forms when the dew point temperature (where water vapor becomes visible) equals the ambient temperature. Fog rarely forms in the summer in Alaska because the ambient temperature is significantly higher than the dew point temperature, even near waterbodies. Spring and fall are the times of the year when fog is more likely to form, especially in areas near large waterbodies that have higher dew point temperatures.

In the Fairbanks vicinity, thunderstorms are about three times more frequent over the hills to the north and east of the city than in other local areas. Damaging hail or wind rarely accompanies thunderstorms in this area (NCDC 2011). Cold snaps in Fairbanks accompanied by winter ice fog generally last about a week, but can last three weeks in unusual situations. The fog is almost always less than 300 feet thick, so that the surrounding uplands are usually clear, with warmer temperatures. Visibility in the ice fog is sometimes quite low, and this can hinder aircraft operations for as much as a day in severe cases (WRCC 2011).

Interior winter temperatures can reach low enough levels (-20 degrees Fahrenheit [°F] to -60°F) to create ice fog on a fairly frequent basis. As cold air is more dense, cold high-pressure systems are formed which are very difficult to displace. Thus, stable conditions with no wind can persist for several days and weeks causing long-lasting ice fogs in Interior locations (NCDC 2011).

9.2.1.6 Limitations of the Station Network and Parameters to Support Air Dispersion Modeling

While climate summaries for a number of stations within the Project vicinity may be obtained from a variety of different climate agencies, these monitoring programs do not provide complete sequential hourly data collected over a long enough period to support air dispersion modeling for regulatory applications. Such modeling, which will be performed as part of the air quality permitting process for APP facilities, requires valid hourly data for at least one year with good data-capture for a number of specific parameters, including temperature, wind speed, wind direction, cloud cover and ceiling height, solar radiation and cloud cover, solar radiation and vertical temperature difference, standard deviation of vertical wind speed or standard deviation of horizontal wind direction. Surface meteorological data of sufficient quantity and quality to support air dispersion modeling are presently available only on the North Slope and in the Fairbanks area. In order to ensure that adequate meteorological data will be available to support air dispersion modeling for permitting of Project facilities, APP is working with the Alaska Department of Environmental Conservation (ADEC) to determine appropriate locations and instrumentation for several monitoring stations that will be established and operated by APP. The objective will be to obtain a minimum of one year of model input data for locations that are reasonably representative of conditions at the GTP and Project compressor stations.

9.2.2 EXISTING AMBIENT AIR QUALITY

Federal and state air emissions regulations are designed to ensure that new sources do not contribute to an exceedance of the ambient standards for criteria air pollutants. The criteria pollutants are sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_x), ozone (O_3), particulate matter having an aerodynamic diameter of 10 microns or less (PM_{10}), particulate matter having an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), and lead (Pb). The U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for these seven pollutants. The NAAQS are set at levels the EPA believes are necessary to protect human health (primary standards) and human welfare (secondary standards).

ADEC has established similar ambient air quality standards referred to as Alaska Ambient Air Quality Standards (AAAQS). AAAQS are similar to the federal NAAQS for criteria pollutants, except for nitrogen dioxide (NO_2). ADEC also has an 8-hour AAAQS for ammonia and a 30-minute standard for total reduced sulfur. Table 9.2.2-1 lists both the federal and state ambient air quality standards.

TABLE 9.2.2-1

Alaska Pipeline Project
Ambient Air Quality Standards in the Project Vicinity

Air Pollutant	Averaging Period	National Ambient Air Quality Standards[a]	Alaska Department of Environmental Conservation Standards[b]
Sulfur Dioxide	1-Hour[c]	75 ppbv[c]	75 ppbv[c]
	3-Hour	1,300[c] µg/m³	1,300 [c] µg/m³
	24-Hour	365 µg/m³	365 µg/m³
	Annual	80 µg/m³	80 µg/m³
Carbon Monoxide	1-Hour	40 mg/m³	40 mg/m³
	8-Hour	10 mg/m³	10 mg/m³
Nitrogen Oxide	1-Hour[d]	100 ppbv[d]	NA
	Annual	100 µg/m³	100 µg/m³
Ozone	8-Hour	0.075 ppmv	0.075 ppmv
Particulate Matter less than 10 microns	24-hour	150 µg/m³	150 µg/m³
Particulate Matter less than 2.5 microns	24-Hour[e]	35 µg/m³	35 µg/m³
	Annual	15 µg/m³	15 µg/m³
Lead	Rolling3-Month Average	0.15µg/m³	0.15 µg/m³
Ammonia	8-Hour	---	2.1 mg/m³
Reduced Sulfur Compounds	30-Minute[f]	---	50 µg/m³

[a] EPA 2011a.
[b] 18 Alaska Administrative Code (AAC) 50.010.
[c] Standard is attained when the 3-year average of the 99th percentile of the distribution of daily maximum values is less than 75 ppb.
[d] Standard is attained when the 3-year average of the 98th percentile of the distribution of daily maximum values is less than 100 ppb.
[e] Standard is attained when the 3-year average of the 98th percentile of the distribution of daily values is less than 35 µg/m³.
[f.] Standard is referenced to sulfur dioxide and is not to be exceeded more than once per year
--- Not available in the vicinity of the Project.
µg/m³ - micrograms per cubic meter
mg/m³ - milligrams per cubic meter
ppbv - parts per billion by volume
ppmv - parts per million by volume
N/A - not applicable

EPA designates all areas of the U.S. as “attainment,” “nonattainment,” “unclassified,” or “unclassified/attainment” with respect to ambient air quality standards. All parts of the Project area are currently designated as attainment or unclassified for all criteria pollutants with the exception of the Fairbanks North Star Borough nonattainment area ($PM_{2.5}$). This same area is also currently designated as a maintenance area with respect to carbon monoxide because of its previous nonattainment status for that pollutant. Only Project construction emissions will occur in the Fairbanks North Star Borough, including but not limited to Project-related truck traffic and heavy equipment operation during construction. None of the permanent emission-producing facilities (i.e., the GTP and compressor stations) are located within any Alaska nonattainment area.

APP reviewed air quality data from ADEC to characterize the background air quality related to regulated criteria pollutants. Monitored data from the PBU are shown in Table 9.2.2-2. The data shown in Table 9.2.2-2 are representative of the background concentrations in the vicinity of the GTP.

TABLE 9.2.2-2

Alaska Pipeline Project
Monitored Air Quality Data from Prudhoe Bay Unit

Air Pollutant	Averaging Period	Maximum Monitored Concentrations	Site Location	Year
Sulfur Dioxide	Annual	0.00091 ppmv	A-PAD	2009
	24-Hour	0.0018 ppmv	A-PAD	2009
	3-hour	0.0037 ppmv	A-PAD	2009
	1-hour[a,b]	3.67 ppbv	A-PAD	2009
Carbon Monoxide	1-hour	1.53 ppmv	Liberty	2008
	8-hour	0.96 ppmv	Liberty	2008
Nitrogen Dioxide	Annual	3.99 ppbv	A-PAD	2009
	1-hour	72.02 ppbv	A-PAD	2009
	Daily Maximum 1-Hour (98thPercentile)[b,c]	43.99 ppbv	A-PAD	2009
Ozone	1-hour	0.046 ppmv	A-PAD	2009
	8-hour	0.043 ppmv	A-PAD	2009
Particulate Matter less than 10 microns	24-hour	25.16 μg/m^3	Central Compression Plant	2009
Particulate Matter less than 2.5 microns	24-hour	10 μg/m^3	Badami	2009
	Annual	2 μg/m^3	Badami	2009

[a] The EPA promulgated the SO_2 1-hour standard on June 2, 2010. To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppbv. The 1-hour average shown in the table reflects the overall maximum 1-hour SO_2 concentration recorded during the annual monitoring period, and does not reflect the statistical value reflected in the new air quality standard.

[b] The State of Alaska has not yet adopted the new 1-hour NO_2 standard (the State of Alaska has a State Implementation Plan [SIP]-approved Prevention of Significant Deterioration [PSD] program, rather than a delegated PSD program). The daily maximum 1-hour 98th percentile NO_2 concentrations recorded during the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[c] The EPA promulgated the NO_2 1-hour standard on February 9, 2010. To attain this standard, the 3-year average of the 98thpercentile of the daily maximum 1-hour average at each monitor within an area must not exceed 0.100 ppmv. The 1-hour average shown in the table reflects the overall maximum 1-hour NO_2 concentration recorded during the annual monitoring period, and does not reflect the statistical value reflected in the new air quality standard. The value labeled Daily Maximum 1-hour (98thpercentile) is the data value for A Pad based on the same calculation as the new NO_2 1-hour standard.

[d] PM_{10} measurements were calculated based on the sample flow rate corrected to standard atmospheric conditions (pressure of 1 atmosphere and 25 degrees Celsius) at the Central Compression Plant.

μg/m^3 - micrograms per cubic meter
mg/m^3 - milligrams per cubic meter
ppbv - parts per billion by volume
ppmv - parts per million by volume
Sources: Enviroplan Consulting 2010

The facility locations within the PBU shown in Table 9.2.2-2 are all within a 30-mile radius of the GTP, and the data from these monitoring stations are considered to be reasonably representative of background air quality for the part of the Project north of Atigun Pass.

Interior Alaska is sparsely populated; therefore, there are very few monitoring stations for criteria pollutants in the region. Fairbanks is the largest metropolitan area in the vicinity of the pipeline route. The only other monitoring station within approximately 100 miles of the Alaska Mainline or PT Pipeline measures O_3 concentrations within Denali National Park. Table 9.2.2-3 presents representative monitored data from Fairbanks and Denali for $PM_{2.5}$, CO, and O_3 (EPA 2011a).

TABLE 9.2.2-3

Alaska Pipeline Project
Monitored Air Quality Data from Interior Alaska

Air Pollutant	Averaging Period	Monitored Concentrations	Site Location	Year
Sulfur Dioxide	Annual	---	---	---
	24-Hour	---	---	---
	3-hour	---	---	---
	1-hour	---	---	---
Carbon Monoxide	1-hour	8.1 ppmv	Federal Building Fairbanks	2008
	8-hour	3.6 ppmv	Federal Building Fairbanks, AK	2008
Nitrogen Dioxide	Annual	---	---	---
	1-hour	---	---	---
	Daily Maximum 1-Hour (98th Percentile)	---	---	---
Ozone	1-hour	0.079 ppmv	Denali	2008
	8-hour	0.076 ppmv	Denali	2008
Particulate Matter less than 10 microns	24-hour	---	---	---
Particulate Matter less than 2.5 microns	24-hour	40.4 μg/m^3	State Office Building Fairbanks	2008
	Annual	8.65 μg/m^3	State Office Building Fairbanks	2008

--- Not available in the vicinity of the Project area.
μg/m^3 - microgram per cubic meter
ppmv - parts per million by volume
Source: EPA 2011b

Tables 9.2.2-2 and 9.2.2-3 summarize a portion of publicly available monitoring data in the Project vicinity. APP will work with ADEC to determine whether available data can be used for the pre-application ambient air analyses required by the Prevention of Significant Deterioration (PSD) program. If available data is not sufficient, APP will coordinate with ADEC to determine appropriate locations for the collection of current data in the vicinity of the Project as discussed in Section 9.2.4.2.

9.2.3 CLASS I AREAS

Certain lands are designated as Class I Areas as a part of the Clean Air Act (CAA). Class I Areas are designated because their air quality is considered a special attribute of these locations (e.g., national parks, wilderness areas, national forests). Class I Areas are protected against several types of pollution including criteria pollutant concentrations, visibility degradation, and acidic deposition.

There are four Class I areas in the state: Bering Sea Wilderness Area; Denali National Park; Simeonof Wilderness Area; and Tuxedni Wilderness Area (EPA 2011c). As shown on Figure 9.2.3-1, all Aboveground Facilities[7] are located at least 80 miles (approximately 129 kilometers) from the nearest Class I Area (Denali National Park).

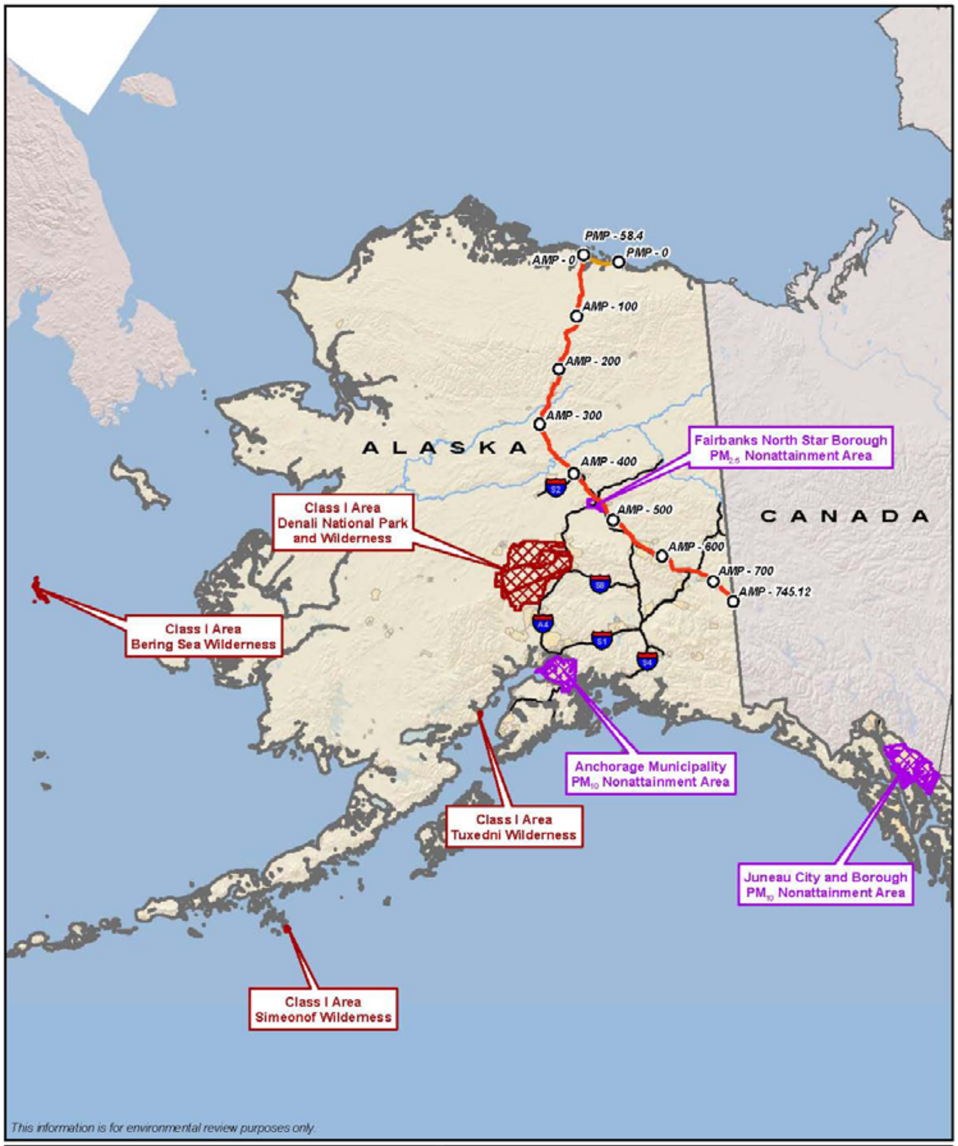

Figure 9.2.3-1
Alaska Pipeline Project
Class I and Nonattainment Areas

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7 Aboveground Facilities include the GTP, eight compressor stations, three custody meter stations, various mainline block valves (MLBV), pig launchers, pig receivers, provisions for intermediate gas delivery points, and cathodic protection facilities as discussed in Section 1.3.2 of Resource Report 1.

9.2.4 AIR EMISSIONS AND REGULATORY REQUIREMENTS FOR AIR QUALITY

Air quality in the United States is federally regulated in the CAA and its amendments as well as state laws and regulations. The regulations promulgated in accordance with the CAA generally regulate three types of air pollutants: criteria pollutants, hazardous air pollutants, and other regulated pollutants. Criteria pollutants are those pollutants for which a NAAQS has been established. One exception to this is volatile organic compounds (VOCs). VOCs are regulated criteria pollutants because they are precursors to ground-level O_3 formation. Hazardous air pollutants (HAPs) are those pollutants that are defined in Section 112 of the CAA, as amended (e.g., benzene, toluene, ethylbenzene, xylene). Other regulated pollutants (e.g., greenhouse gases [GHGs]) are any other pollutants subject to new source performance standards (NSPS), ozone-depleting substance regulations, vehicle emission standards, or other regulations.

9.2.4.1 Operating Emissions

This section summarizes the current estimated potential to emit criteria pollutant, HAPs, and GHG emissions from APP facilities during normal operations. The paragraphs below and Appendix 9A further describe the equipment and calculation methodologies utilized to estimate these emissions.

Gas Treatment Plant Operating Emissions

The preliminary design of the GTP consists of four identical gas processing trains that perform carbon dioxide (CO_2) hydrogen sulfide (H_2S), and water removal, and sales gas and CO_2 stream compression. Refer to Section 1.3.2.1, Figure 1.3.2-1, and Appendix 1B of Resource Report 1 for a detailed description of GTP activities.

Emission sources associated with the processes in each train include one natural gas-fired sales gas compressor turbine and one natural gas-fired CO_2 compressor turbine. Additionally, emissions of air pollutants will result from operation of the following common equipment that will serve the GTP as a whole:

- Six natural gas-fired power generator turbines;
- Three natural gas-fired essential power generator turbines;
- One natural gas-fired auxiliary heater;
- One diesel-fired emergency generator;
- Two diesel-fired essential generators;
- One diesel-fired air compressor;
- One diesel-fired firewater pump;
- Several aboveground storage tanks; and
- Eight elevated flare tips

Fugitive emissions of organic compounds, including some HAPs, will likely come from piping components and connectors throughout the GTP. Table 9.2.4-1 lists the estimated operational emissions from normal operation of the GTP, including the stationary sources listed above as well as on-road and off-road support equipment and vehicles.

TABLE 9.2.4-1

Alaska Pipeline Project
Estimated Air Emissions from Operations of the Gas Treatment Plant

Pollutant	Project Potential To Emit (pounds per hour)	Project Potential To Emit (tons per year)
Nitrogen Oxides (NO_x)	1,317	3,839
Carbon Monoxide (CO)	492	1,718
Volatile Organic Compounds (VOCs)	92	207
Particulate Matter (PM_{10})	83	284
Particulate Matter ($PM_{2.5}$)	83	284
Sulfur Dioxide (SO_2)	151	597
Lead (Pb)	0	0
Largest Individual Hazardous Air Pollutant (Formaldehyde)	9.02	11.8
Total Hazardous Air Pollutants (HAP)	13.6	21.8
Carbon Dioxide (CO_2)[a]	1,354,045	4,418,755
Nitrous Oxide (N_2O)[a]	37	134
Methane (CH_4)[a]	167	624
Total Greenhouse Gas Emissions (CO_2e)[a,b]	1,368,909	4,473,262

[a] Annual emissions given in tonnes per year.
[b] The total GHG emissions are calculated as CO_2 equivalent (CO_2e) emissions, i.e., the sum of individual GHGs with the annual tonnes of each gas multiplied by its Global Warming Potential (GWP) relative to CO_2. CH_4 is converted to CO_2e by multiplying its emissions by the GWP of 21, and N_2O is converted to CO_2e by multiplying its emissions by the GWP of 310.

Note that not all GTP emission units operate 8,760 hours per year (e.g., diesel-fired equipment). Appendix 9A provides information on how the operational emissions of the GTP were calculated. Annual turbine emissions are based on assumed operation at full load using vendor emission rates for a reference ambient temperature of 10°F. Sample emission factors from all equipment are from published EPA compilations and/or vendor-provided data, as detailed in Appendix 9A.

Compressor Station Operating Emissions

Preliminary designs for all eight compressor stations are similar and include the following emission units:

- One or more stationary natural gas-fired turbines;
- Two natural gas-fired generators;
- Eight natural gas-fired utility glycol heaters; and
- One natural gas-fired waste-handling incinerator.

Fugitive emissions of organic compounds, including some HAPs, will likely come from piping components and connectors throughout the compressor station. Table 9.2.4-2 lists the estimated operational emissions from normal operation of each compressor station's preliminary design.

TABLE 9.2.4-2

Alaska Pipeline Project
Estimated Air Emissions from Operations of each Compressor Station

Pollutant	Potential To Emit (pounds per hour)	Project Potential To Emit (tons per year)
Nitrogen Oxides (NO_x)	33.2	145.5
Carbon Monoxide (CO)	28.1	123.0
Volatile Organic Compounds (VOCs)	10.4	45.6
Particulate Matter (PM_{10})	4.3	18.6
Particulate Matter ($PM_{2.5}$)	4.3	18.6
Sulfur Dioxide (SO_2)	4.8	20.7
Lead (Pb)	0	0
Largest Individual Hazardous Air Pollutant (Formaldehyde)	0.4	1.6
Total Hazardous Air Pollutants (HAP)	0.6	2.4
Carbon Dioxide (CO_2) [a]	40,864.7	161,089
Nitrous Oxide (N_2O) [a]	0.08	0.3
Methane (CH_4) [a]	6.58	25.94
Total Greenhouse Gas Emissions (CO_2e) [a,b]	41,003.1	161,726

[a] Annual emissions given in tonnes/year

[b] The total GHG emissions are calculated as CO_2e emissions, i.e., the sum of individual GHGs with the annual tonnes of each gas multiplied by its GWP relative to CO_2. CH_4 is converted to CO_2e by multiplying its emissions by the GWP of 21, and N_2O is converted to CO_2e by multiplying its emissions by the GWP of 310.

Once the detailed engineering design is finalized, individual emission calculations will be determined for each compressor station, which may differ slightly from location to location due to elevation. Note that the air emissions provided in the table above are based on the assumption that all emitting equipment operate 8,760 hours per year. Annual turbine emissions are based on assumed operation at full load using vendor emission rates at an annual average temperature of 0°F. Sample emission factors from all equipment are from published EPA compilations and/or vendor-provided data, as detailed in Appendix 9A. Note that the individual HAP expected to have the highest annual emissions from each compressor station is formaldehyde.

Miscellaneous Aboveground Facilities Operating Emissions

Fugitive emissions of organic compounds, including some GHGs, will likely come from piping components and connectors along the pipeline. The Interstate Natural Gas Association of America has created guidance for calculating methane (CH_4) and CO_2 leak emissions, both considered GHG emissions, from a natural gas pipeline. The methodology utilizes the length of the pipeline and the number of meter stations to determine an estimate of the annual fugitive emissions. Table 9.2.4-3 summarizes the estimated annual fugitive GHG emissions for APP (excluding the GTP and compressor station fugitives which are included in Tables 9.2.4-1 and 9.2.4-2, respectively) based on 803.5 miles of pipeline (58.4 miles for the PT Pipeline and 745.1 miles for the Alaska Mainline) and a meter station (the two other meter stations are located within the GTP boundaries and will be accounted for in GTP emissions).

TABLE 9.2.4-3

Alaska Pipeline Project
Estimated Fugitive Greenhouse Gas Emissions

Pollutant	Segment	Emission Factor [a,b]	Emissions (pounds per year)	Emissions (tonnes per year)
Methane (CH_4)	Meter/Regulator	2,533.0	2,533	1.15
	Pipeline Length	23.1	18,561	8.42
Carbon Dioxide (CO_2)	Meter/Regulator	146.3	146.3	0.07
	Pipeline Length	1.5	1205	0.55
CO_2 from CH_4 oxidation	Pipeline Length	7.6	6,107	2.8
Total Greenhouse Gas Emissions (CO_2e) [c]			450,437	204.3

[a] The meter/regulator emission factor is in units of pounds per station per year.
[b] The pipeline length emission factor is in units of pounds per mile per year.
[c] The total GHG emissions are calculated as CO_2e emissions, i.e., the sum of individual GHGs with the annual tonnes of each gas multiplied by its GWP relative to CO_2. CH_4 is converted to CO_2e by multiplying its emissions by the GWP of 21, and N_2O is converted to CO_2e by multiplying its emissions by the GWP of 310.
Source: Interstate Natural Gas Association of America 2005, Table 4-3.

Provisions of the CAA potentially applicable to APP based on the preliminary equipment and emission rates identified above are described in the following sections and include the PSD Permit Program, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAPs), the Operating Permit Program, and General Conformity.

9.2.4.2 Startup, Shutdown, and Malfunction Operations

[Note: APP is evaluating emissions related to startup, shutdown, and malfunction conditions and will update these emissions in the final report or in subsequent PSD applications.]

9.2.4.3 Prevention of Significant Deterioration and New Source Review

Ambient air quality is protected by the EPA's New Source Review (NSR) regulations. The NSR regulations consist of rules for attainment area pollutants (known as the PSD rules) and nonattainment area pollutants (known as the nonattainment NSR [NNSR] rule). Except for a small (2.5-mile) section of the Alaska Mainline route which falls within the Fairbanks North Star Borough $PM_{2.5}$ nonattainment area, all permanent APP emissions-generating facilities will be located in areas that attain all the NAAQS for all pollutants. Therefore, PSD, rather than NNSR, applies to emissions of criteria pollutants and other pollutants such as GHGs. The NSR regulations do not apply to HAPs unless the HAP is a constituent of or precursor to a criteria pollutant. EPA has approved Alaska's PSD rules allowing ADEC to implement PSD through the state rules. For PSD, the ADEC Air Quality program adopts the PSD regulations by reference from 40 C.F.R. § 52.21 (refer to 18 Alaska Administrative Code [AAC] 50.306). PSD applies to major stationary sources and to all regulated pollutants emitted in significant amounts by a new major stationary source. GTP and the eight compressor stations are major sources for PSD.

To determine whether APP is sufficiently large in terms of emissions to be considered a "major" stationary source, source size is defined in terms of "potential to emit," which is its capability at maximum design capacity to emit a pollutant, except as constrained by federally enforceable permit conditions. Under the PSD rules, a "major stationary source" is one that emits or has the potential to emit:

- For categorical sources (40 C.F.R. § 52.21[b][1][i][a]) – 100 tons per year (tpy) or more of a regulated air contaminant (other than GHGs) in an area designated attainment for that air contaminant; or
- For other sources –
  - 250 tpy or more of a regulated air contaminant (other than GHGs) in an area designated attainment for that air contaminant;
  - 100,000 tpy of CO_2 equivalent (CO_2e) emissions of the six GHGs combined; and
  - 250 tpy mass emissions of the six GHGs.

40 C.F.R. § 52.21 defines 28 Categorical Sources. Gas treatment plants and compressor stations are not included in the source types listed in 40 C.F.R. § 52.21; therefore, 250 tpy is the threshold for determining major source status for all criteria pollutants other than GHGs for the GTP and individual compressor stations associated with APP.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP).

For PSD purposes, GHGs are characterized as a single air pollutant defined as the aggregate group of the following six gases:

- CO_2;
- Nitrous oxide (N_2O);
- CH_4;
- Hydroflurocarbons;
- Perfluorocarbons; and
- Sulfur hexafluoride.

PSD applies to regulated pollutants emitted in "significant" amounts by the Project. Significant increases in emission rates are subject to PSD review in two circumstances.

- For a new source which is major for at least one regulated attainment pollutant, all pollutants for which the area is classified as attainment and which are emitted in amounts equal to or greater than those specified in Table 9.2.4-4.
- For a new major stationary source, any emission rate at the new source that is constructed within 10 kilometers of a Class I area, and which will increase the 24-hour average concentration of any regulated pollutant in that area by 1 microgram per cubic meter ($\mu g/m^3$) or greater.

TABLE 9.2.4-4

Alaska Pipeline Project
Prevention of Significant Deterioration Significance Emission Rates

Pollutant	Prevention of Significant Deterioration Significant Emission Rate (tons per year)
Nitrogen Oxides (NO_x)	40
Carbon Monoxide (CO)	100
Volatile Organic Compounds (VOC)	40
Particulate Matter (PM_{10})	15
Particulate Matter ($PM_{2.5}$)	10
Sulfur Dioxide (SO_2)	40
Lead (Pb)	0.6
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10
Total Greenhouse Gas Emissions (CO_2e)	75,000

Source: 40 C.F.R. 52.21.

The applicable PSD requirements include the following components that must be addressed in a PSD permit application.

- Apply Best Available Control Technology (BACT) for each regulated pollutant for which the major modification would result in a significant net emissions increase (§ 52.21[j][3]).
- Conduct an air quality impact analysis that demonstrates emissions associated with the proposed new source or modification, in conjunction with all other emission increases and decreases, will not cause or contribute to violations of any NAAQS or allowable PSD increment. Establish the maximum modeled impact as part of this analysis (§ 52.21[k]).
- Provide a pre-application ambient air analysis based on current data collected in the vicinity of the Project (§ 52.21[m]).
- Provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the stationary source and general commercial, industrial, residential and other growth associated with the stationary source (§ 52.21[o][1]).
- Provide an analysis of the projected additional air quality impact as a result of general commercial, industrial, residential, and other growth associated with the stationary source (§ 52.21[o][2]).
- Provide an analysis of the impacts to air quality and air quality-related values at nearby Class I areas (§ 52.21[p]).

Gas Treatment Plant

Table 9.2.4-1 lists the estimated operational emissions for the GTP. As shown in Table 9.2.4-1, the GTP's GHG emissions will be greater than 250 tpy in aggregate mass and greater than 100,000 tpy of CO_2e, thus meeting the definition as a major source. Additionally, the GTP potentially can emit NO_x, SO_2, CO, VOC, PM_{10}, and $PM_{2.5}$ in amounts greater than 250 tpy, thus meeting the definition as a major source for each of these pollutants. Therefore, NO_x, SO_2, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG emissions from the GTP are subject to PSD review.

Since the GTP will be located in an area designated in attainment for all criteria pollutants and will be a major source for at least one criteria pollutant, all remaining criteria pollutants emitted in significant amounts from the GTP will be subject to PSD review. The definition of significant under the PSD rule is any net emissions increase or potential to emit that is greater than the levels identified in Table 9.2.4-4, or any net emission increase or potential to emit associated with a major source or major modification constructed within 10 kilometer of a Class I area that has an impact equal to or greater than 1 microgram per cubic meter (24-hour average). The GTP is well over 10 kilometer from any Class I area; as such, the secondary definition of a significant emissions increase does not apply. Therefore, the GTP will only be significant for other pollutants if they are over the levels listed in Table 9.2.4-4.

The GTP is located in an area designated as attainment for all criteria pollutants; therefore, PSD regulations will apply to the GTP for all criteria pollutants requiring PSD review as determined by the first two criteria described previously. As such the GTP is subject to PSD review for NO_x, SO_2, CO, VOC (O_3), PM_{10}, $PM_{2.5}$, and GHGs.

Compressor Stations

Table 9.2.4-2 lists the representative estimated operational emissions for an individual compressor station. As shown in Table 9.2.4-2, each compressor station's GHG emissions are greater than 250 tpy in aggregate mass and greater than 100,000 tpy of CO_2e, thus meeting the definition as a major source. Based on this criterion, each compressor station is a major source only for GHG emissions.

Since each compressor station will be located in an area designated in attainment for all criteria pollutants and each will be a major source of GHG emissions, all remaining regulated pollutants emitted in significant amounts from each compressor station will be subject to PSD review. As shown in Table 9.2.4-2, the estimated potential emissions of NO_x, CO, VOC, PM_{10}, and $PM_{2.5}$ from a single compressor station all potentially exceed the applicable significance thresholds listed in Table 9.2.4-4. As such, each compressor station is subject to PSD review for NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and GHGs. Because each compressor station is well beyond 10 kilometers from any Class I area, the secondary definition of a significant emissions increase does not apply. All of the compressor stations are located at least 80 miles (approximately 129 kilometers) from the nearest Class I Area (Denali National Park) located well over 10 kilometers away, as such, the secondary definition of a significant emissions increase does not apply.

9.2.4.4 New Source Performance Standards

NSPS set by EPA for newly constructed or modified emission sources are specific control technology, performance standards, or work practices for specific emissions units. These standards are authorized by Section 111 of the CAA, and the regulations are published in 40 C.F.R. Part (pt.) 60. The standards that apply to the GTP include standards in Subparts A, Db, VVa, KKK, LLL, IIII, and KKKK. Subparts A, JJJJ, and KKKK apply to the compressor stations.

Gas Treatment Plant

NSPS Subpart A establishes general provisions for sources subject to the various NSPS subparts including performance testing, work practice, notification, reporting, and recordkeeping requirements. In addition, the GTP is subject to the flare design requirements of Subpart A for the flares that will burn off gases during upsets in all processing units.

NSPS Subpart Db applies to industrial, commercial, institutional steam-generating units listed in 40 C.F.R. §§ 60.40b to 60.49b, inclusive. The natural gas-fired heaters with a heat input of greater than 100 million British thermal units (MMBtu per hour) will be subject to the NO_x requirements of this subpart.

NSPS Subpart VVa establishes standards for equipment leaks from synthetic organic chemical manufacturing facilities. NSPS Subpart VVa incorporates many of the basic requirements of Subpart VV, with some exceptions such as detection levels for determining leaking equipment. Therefore, APP will incorporate any applicable provisions of Subpart VVa.

NSPS Subpart KKK establishes standards for equipment leaks of VOC from onshore natural gas processing plants. Subpart KKK is applicable to the GTP.

The GTP is also subject to the requirements of NSPS Subpart LLL which is the NSPS for Onshore Natural Gas Processing: SO_2 emissions.

NSPS Subpart IIII applies to stationary compression ignition internal combustion engines and diesel generator engines at the GTP. The requirements of this Subpart include emission standards, diesel fuel specifications, monitoring, and recordkeeping.

NSPS Subpart KKKK was promulgated on July 6, 2006, and applies to all new turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour that commence construction, modification, or reconstruction after February 18, 2006. The combustion turbines of the GTP will be subject to the NO_x and SO_2 requirements of this subpart.

Compressor Stations

The natural gas engine-driven generators for each compressor station will be subject to NSPS Subpart JJJJ: "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines." Pursuant to these regulations, all generators will be required to meet emission standards for NO_x, CO, and VOC.

NSPS Subpart KKKK was promulgated on July 6, 2006, and applies to all new turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour that commence construction, modification, or reconstruction after February 18, 2006. The combustion turbines located at each compressor station will be subject to the NO_x and SO_2 requirements of this subpart.

[Note: APP is evaluating the applicability of the NSPS regulations described in this section and will update how compliance will be achieved with these regulations and other applicable regulations in the final report and/or subsequent PSD applications.]

9.2.4.5 National Emission Standards for Hazardous Air Pollutants

The 1970 CAA required the EPA to develop health-risk-based standards for regulating HAP emissions. These regulations are known as NESHAPs and are codified in 40 C.F.R. pt. 61. These standards apply to specific pollutants and source categories. The 1990 CAA expanded EPA's obligation to regulate HAPs and required EPA to set technology-based standards for a larger list of HAPs and for many more source categories. These NESHAPs are codified in 40 C.F.R. pt. 63 and are known as the maximum achievable control technology (MACT) standards.

None of the facilities included in APP will be subject to the 40 C.F.R. pt. 61 NESHAP, however, the MACT standards may be applicable. The following subsections discuss the potential applicability of each MACT standard.

Gas Treatment Plant

Emission sources within the GTP include combustion turbines, reciprocating engines, heaters, dehydration units, flares, and fugitive equipment leaks. A sample list of emission units is included in the emission calculations in Appendix 9A. The GTP has potential HAP emissions greater than the major source thresholds for a single HAP (10 tpy) as summarized in Table 9.2.4-1. Therefore, the GTP is considered a major source of HAPs. GTP is potentially subject to Subparts A, H, HH, ZZZZ, and DDDDD of 40 C.F.R. pt. 63.

Subpart A provides the general provisions of the MACT standards. These include such requirements as notification and reporting requirements for sources subject to subparts discussed below.

Subpart H establishes a leak detection and repair program for pumps, compressors, agitators, pressure-relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed-vent systems required by Subpart H that are intended to operate in organic HAP service. Subpart H includes equipment design requirements as well as leak detection and repair.

Subpart HH applies to oil and natural gas production facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. The affected sources for major sources of HAPs are the glycol dehydration units, storage vessels with potential flash emissions, and ancillary equipment intended to operate in volatile HAP service. The GTP will include dehydration units and associated ancillary equipment. This equipment is potentially subject to Subpart HH. Subpart HH establishes emission control as well as monitoring and recordkeeping requirements for glycol dehydration units and storage vessels with potential flash emissions. Any equipment that is subject to Subpart HH and NSPS Subpart KKK must only comply with NSPS Subpart KKK.

Subpart HHH applies to natural gas transmission and storage facilities that are major sources of HAPs. Subpart HHH states that a compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. Therefore, the GTP is subject to 40 C.F.R. pt. 63 Subpart HH for natural gas processing plants rather than Subpart HHH.

Subpart YYYY applies to stationary combustion turbines at major stationary sources of HAPs, however, turbines located on the North Slope are exempt from the requirements of this subpart, except for the initial notification requirements.

Subpart ZZZZ applies to compression ignition reciprocating engines at major and area sources of HAPs. Subpart ZZZZ will apply to the diesel generator engines at the GTP. With the exception of the essential diesel generators, these engines are intended for emergency use only and rated at less than 500 horsepower. Under Subpart ZZZZ, these engines will be subject to the requirements of the NSPS Subpart IIII. The three essential diesel generators will be more than 5,000 horsepower each and operate on a limited-use basis. These generators are subject to the general duty provision of 40 C.F.R. § 63.6605 to operate and maintain the affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions and the notification requirements of 40 C.F.R. § 63.6645.

Subpart DDDDD applies to boilers and process heaters at major sources of HAPs, however, EPA has chosen to delay the effective date of Subpart DDDDD until proceedings for judicial review are completed or EPA completes its reconsideration of the rule, whichever is earlier. In its current form, Subpart DDDDD will apply to the GTP. Because the GTP fired heaters burn natural gas, the affected units under Subpart DDDDD in its current form will be subject to work practice standards, rather than emission limits for specific HAPs.

Compressor Stations

The natural gas engine-driven generators for each compressor station will be subject to NESHAP Subpart ZZZZ: "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines."

According to the standards, if the owners and operators of an internal combustion engine are in compliance with NSPS Subpart JJJJ, they will also be in compliance with NESHAP Subpart ZZZZ for new and reconstructed engines located at a NESHAP area source. Each compressor station will be classified as a NESHAP area source because the annual emissions of all individual HAPs at each station will be less than 10 tpy, and the annual emissions of total HAPs at each station will be less than 25 tpy.

Therefore, the generators at each compressor station will be considered to be in compliance with NESHAP Subpart ZZZZ as long as they are operated in compliance with NSPS Subpart JJJJ. Because each compressor station will not be a major source of HAPs, they are exempt from the MACT standards that address other types of station equipment.

[Note: APP is evaluating the applicability of the NESHAP regulations in this section and will update how compliance will be achieved with these regulations and other applicable regulations in the final report and/or subsequent PSD applications.]

9.2.4.6 Title V Operating Permits

Title V Operating Permits will be required for the GTP and each individual compressor station.

Gas Treatment Plant

As shown in Table 9.2.4-1, the total potential emissions of CO, NO_x, VOC, PM_{10}, SO_2, and $PM_{2.5}$ will be greater than the Title V major source threshold of 100 tpy. Potential CO_2e emissions will also exceed the applicable 100,000 ton major source threshold for Title V. The potential emissions of HAPs are above the 10 tpy for an individual HAP threshold. As such, the GTP will be subject to the Title V permitting requirements. APP is required to submit a Title V Operating Permit application to ADEC within 12 months following startup of the GTP.

Compressor Stations

As shown in Table 9.2.4-2, the total potential emissions of NO_x and CO will be greater than the Title V major source threshold of 100 tpy for each compressor station. Potential CO_2e emissions will also exceed the applicable 100,000 ton major source threshold for Title V. The potential emissions of HAPs are below the 10 tpy for an individual HAP and 25 tpy for all combined HAPs threshold. As such, each compressor station will be subject to the Title V permitting requirements. APP is required to submit Title V Operating Permit applications to ADEC within 12 months following startup of each compressor station.

9.2.4.7 Greenhouse Gas Reporting Rule

EPA's Greenhouse Gas Monitoring Recordkeeping and Reporting Rule (40 C.F.R. pt. 98) requires reporting of GHG emissions from suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit greater than or equal to 25,000 metric tons of GHG (as CO_2e) per year. As shown in Table 9.2.4-1 and Table 9.2.4-2, the potential CO_2e emissions from the GTP and each compressor station will exceed 25,000 metric tons per year; therefore, the GTP and each compressor station will be subject to the Mandatory Reporting Rule.

9.2.4.8 Alaska State Air Quality Regulations

ADEC is authorized under state laws and regulations to manage air quality program requirements in the state of Alaska. Therefore, the GTP and each compressor station must meet the requirements of the ADEC air regulations in addition to meeting the federal regulations. ADEC established the18 AAC 50 to regulate air pollution sources. Potentially applicable chapters of the AAC are discussed below.

Article 3, 18 AAC 50.300 through 50.322 establishes construction permitting requirements for stationary sources. In accordance with 18 AAC 50.310, APP must obtain construction permits for the installation of GTP and compressor station equipment which will constitute a major source and the installation of turbines prior to commencement of construction of the emission units. APP will obtain construction permits from ADEC for the GTP and the compressor stations prior to commencing construction of the emission units.

18 AAC 50.055 limits the sulfur compound emissions as SO_2 to 500 parts per million that can be emitted into the ambient air. This rule applies to industrial processes and fuel-burning equipment and will be applicable to the GTP and each compressor station.

18 AAC 50.050 and 50.055 (a)(1) limits the visible emissions and opacity of emissions from industrial processes and fuel-burning equipment. The fuel-burning equipment and other industrial processes will not emit exhaust gases with greater than 20 percent opacity, as required under this provision.

18 AAC 50.065 establishes limits for open burning. If open burning will be used, the provisions of 18 AAC 50.065 will be applicable.

18 AAC 50.080 establishes limits for industrial processes, fuel-burning equipment, and incinerators in areas of potential ice fog. These limits may affect the GTP and the compressor stations and will be determined on a case-by-case basis.

18 AAC 50.215 exempts concentrations attributable to a temporary construction activity from ambient air quality analyses. As such, the construction related to compressor stations, construction camps, and horizontal directional drilling (HDD) sites need not be included in ambient air quality analyses.

18 AAC 50.910 defines "Temporary Construction Activities" as construction that is completed in 24 months or less from the date construction begins. As such, construction of the compressor stations, construction camps, meter stations, and HDD sites qualify as temporary under air quality regulations.

[Note: APP is evaluating the applicability of Alaska state air regulations in this section and will update how compliance will be achieved with these regulations and other applicable regulations in the final report and/or subsequent PSD applications.]

DRAFT

9.2.5 CONSTRUCTION AND OPERATION IMPACTS AND MITIGATION

9.2.5.1 Construction

Air quality impacts associated with construction of APP will include exhaust emissions from fossil fuel-powered construction equipment and fugitive dust.

Earth-moving equipment and other mobile construction sources will be powered by diesel or gasoline engines and are sources of combustion-related emissions including NO_X, CO, VOCs, SO_2, PM_{10}, and small amounts of HAPs. Fuel consumption (diesel fuel and gasoline) during construction activities will vary depending on the specific construction activity and the type of terrain.

Table 9.2.5-1 shows the estimated potential emissions from construction equipment operation during each year for the Project as described in Figure 1.5-1 in Resource Report 1. Sample emission calculations based on published emission quantification methodologies are included in Appendix 9A.

TABLE 9.2.5-1

Alaska Pipeline Project
Estimated Air Emissions from Construction Equipment Operation[a]

Construction Activity	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_x (tpy)	CO (tpy)	SO_x (tpy)	VOC (tpy)	CO_2 (tpy)	CO_2e (Metric ton/year)
GAS TREATMENT PLANT								
Year 2014	0.03	0.03	0.43	0.12	0.00	0.03	107	109
Year 2015	16.07	9.15	108.69	40.39	0.19	7.96	23,804	24,186
Year 2016	16.77	7.91	105.09	48.61	0.16	9.01	19,336	19,647
Year 2017	54.68	16.82	220.77	77.17	0.44	14.98	50,125	50,929
Year 2018	66.17	16.74	235.07	78.32	0.49	14.59	54,076	54,944
Year 2019	51.81	15.22	221.45	76.47	0.47	14.17	52,538	53,381
Year 2020	6.83	4.11	48.13	26.86	0.19	3.67	20,744	21,077
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
GTP Subtotal	212.36	69.98	939.63	347.94	1.94	64.41	220,730	224,273
COMPRESSOR STATIONS								
Happy Valley Compressor Station								
Year 2016								
Year 2017								
Year 2018	21.99	2.38	2.78	1.23	0.01	0.27	667	694
Year 2019	0.04	0.04	0.56	0.25	0.00	0.05	133	139
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Galbraith Lake Compressor Station								
Year 2016								
Year 2017	16.46	1.76	1.67	0.74	0.01	0.16	400	416
Year 2018	5.57	0.66	1.67	0.74	0.01	0.16	400	416
Year 2019								
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Chapman Creek Compressor Station								
Year 2016								
Year 2017								

TABLE 9.2.5-1

Alaska Pipeline Project
Estimated Air Emissions from Construction Equipment Operation[a]

Construction Activity	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_x (tpy)	CO (tpy)	SO_x (tpy)	VOC (tpy)	CO_2 (tpy)	CO_2e (Metric ton/year)
Year 2018	0.04	0.04	0.56	0.25	0.00	0.05	133	139
Year 2019	21.99	2.38	2.78	1.23	0.01	0.27	666	694
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Fort Hamlin Hills Compressor Station								
Year 2016								
Year 2017								
Year 2018								
Year 2019	16.46	1.76	1.67	0.74	0.01	0.16	400	416
Year 2020	5.57	1.76	1.67	0.74	0.01	0.16	400	416
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Tatalina River Compressor Station								
Year 2016								
Year 2017	16.46	1.76	1.67	0.74	0.01	0.16	400	416
Year 2018	5.57	0.66	1.67	0.74	0.01	0.16	400	416
Year 2019								
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Johnson Road Compressor Station								
Year 2016								
Year 2017								
Year 2018	0.04	0.04	0.56	0.25	0.00	0.05	133	139
Year 2019	0.61	0.28	2.78	1.23	0.01	0.27	666	695
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
George Lake Compressor Station								
Year 2016								
Year 2017								
Year 2018								
Year 2019	0.42		1.67	0.74	0.01	0.16		416
Year 2020	0.22		1.67	0.74	0.01	0.16		416
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Tetlin Junction Compressor Station								
Year 2016								
Year 2017								
Year 2018	0.61	0.28	2.78	1.23	0.01	0.27	666	694
Year 2019	0.04	0.04	0.56	0.25	0.00	0.05	133	1389
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Compressor Stations Subtotal	112.09	13.84	26.72	11.84	0.12	2.56	5,597	6,663
PIPELINE								
Alaska Mainline and PT Pipeline								
Year 2016	441.01	48.60	83.35	28.46	0.24	6.47	21,834	22,626

TABLE 9.2.5-1

Alaska Pipeline Project
Estimated Air Emissions from Construction Equipment Operation[a]

Construction Activity	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_x (tpy)	CO (tpy)	SO_x (tpy)	VOC (tpy)	CO_2 (tpy)	CO_2e (Metric ton/year)
Year 2017	1,077.59	121.60	251.15	85.73	0.74	19.60	65,789	68,199
Year 2018	1,446.16	162.71	342.44	115.50	0.99	26.42	89,459	92,694
Year 2019	448.18	52.15	139.10	45.92	0.38	10.38	36,343	37,5549
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Meter Stations								
Year 2016								
Year 2017								
Year 2018								
Year 2019	0.06	0.05	0.83	0.37	0.00	0.08	200	208
Year 2020	0.06	0.05	0.83	0.37	0.00	0.08	200	208
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
HDD Emissions								
Year 2016								
Year 2017	0.10	0.09	1.71	0.50	0.01	0.13	347	366.56
Year 2018	0.43	0.24	3.41	1.00	0.01	0.26	695	733.12
Year 2019	0.20	0.18	3.41	1.00	0.01	0.26	694	733.12
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Construction Camps								
Year 2016	1.03	0.99	17.48	5.48	0.07	1.39	2,394	2,705
Year 2017	5.65	5.48	96.41	30.23	0.40	7.66	13,202	14,918
Year 2018	5.35	5.18	91.17	28.58	0.37	7.25	12,484	14,107
Year 2019	0.88	0.05	14.99	4.70	0.06	1.19	2,052	2,318
Year 2020								
Year 2021	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Pipeline Subtotal	3,426.7	397.37	1,046.28	347.84	3.28	81.17	245,693	257,371
Project Total	**3,751.15**	**481.19**	**2,012.57**	**707.55**	**5.32**	**148.12**	**472,020**	**488,307**

[a] The numbers in this table have been rounded for presentation purposes. As a result, the totals may not reflect the exact sum of the addends in all cases. Some totals may be off by 0.1. PM_{10} emissions include fugitive and exhaust emissions.

CO - Carbon monoxide
CO_2e - Carbon dioxide equivalent
NO_x - Nitrogen oxides
PM_{10} - Particulate Matter less than 10 microns
$PM_{2.5}$ - Particulate Matter less than 2.5 microns
SO_x - Sulfur oxides
VOC - Volatile organic compounds

Emissions from APP's construction activities will be temporary and localized, and are expected to remain within federal or state ambient air quality standards. Fossil fuel-powered construction equipment will be maintained in accordance with manufacturers' recommendations to minimize construction-related emissions from equipment. Further, construction equipment will be operated on an as-needed basis. All activities will be completed in compliance with the applicable ADEC rules and regulations identified in Section 9.2.4.7.

Fugitive dust will result from land clearing, grading, excavation, and vehicle traffic on paved and unpaved roads. The amount of dust generated will be a function of construction activities, soil type, moisture content, wind speed, frequency of precipitation, vehicle traffic, vehicle types, and roadway characteristics. For example, such emissions will be minimal during winter months when the earth is frozen or when ice and/or snow cover are present. Emissions will be greater during dry periods and in areas of fine-textured soils subject to surface activity. Fugitive dust emissions will be addressed on a location-by-location and time-specific basis during periods when wind erosion and dust generation are occurring or probable. Measures that APP may implement to control dust, if necessary, include the following:

- reduction of vehicle speeds on all unpaved roads and unpaved haul and access roads; and
- application of water and/or chemical suppressants, when necessary, to active construction areas to minimize fugitive dust emissions.

Upon completion of construction, APP will stabilize and promote revegetation in areas disturbed by construction in accordance with the APP's Erosion Control, Revegetation, and Maintenance Plan (Plan) requirements (refer to Appendix 1J in Resource Report 1). Therefore, fugitive dust emissions during construction will be minor and of short duration.

9.2.5.2 Operation

Gas Treatment Plant

Air quality impacts from GTP operation will result primarily from combustion emissions from natural gas-fired turbines. APP is currently evaluating the ambient air quality impacts of the GTP in accordance with published guidance on dispersion modeling protocol and available meteorological data. APP will submit a formal modeling protocol to ADEC for concurrence and complete an ambient air quality impact analysis as part of the PSD application for the GTP. The air quality impact analysis will be conducted in accordance with a protocol approved by ADEC.

[Note: Table 9.2.5.2 is included as a placeholder and will be updated in the final report. A copy of the air quality impact analysis for the GTP will be provided to appropriate agencies after completion.]

Air quality impacts will be mitigated through the use of turbines and generators that are compliant with applicable NSPS. In addition, BACT will be applied to emission sources at the GTP due to its major source classification under PSD.

Compressor Stations

Air quality impacts from compressor station operation will result primarily from air pollutant combustion emissions from natural gas-fired turbines and generators. APP is currently evaluating the ambient air quality impacts of a typical compressor station in accordance with published guidance on dispersion modeling protocol and available meteorological data. APP will submit a formal modeling protocol to ADEC for concurrence and complete an ambient air quality impact analysis as part of the PSD application for each compressor station. Modeling results for individual compressor stations will reflect local terrain and meteorological conditions, as well as slight variations in equipment emissions due to local conditions. Each air quality impact analysis will be conducted in accordance with a protocol approved by ADEC.

TABLE 9.2.5-2

Predicted Pollutant Concentrations for Comparison with National Ambient Air Quality Standards and Alaska Ambient Air Quality Standards – Gas Treatment Plant Base Case Normal Operations

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	National Ambient Air Quality Standards (µg/m3)	Alaska Ambient Air Quality Standards ($\mu g/m^3$)
NO_2	Maximum 1-hour design value[a,b]	TBD	TBD	TBD	188	--
	Annual average	TBD	TBD	TBD	100	100
SO_2	Maximum 1-hour design value[a]	TBD	TBD	TBD	196	196
	3-hour 1st highest	TBD	TBD	TBD	1,300	1,300
	24-hour 1[st]highest[b]	TBD	TBD	TBD		365
	Annual average[b]	TBD	TBD	TBD		80
CO	1-hour 1st highest	TBD	TBD	TBD	40,000	40,000
	8-hour 1st highest	TBD	TBD	TBD	10,000	10,000
PM_{10}	24-hour 4th highest	TBD	TBD	TBD	150	150
$PM_{2.5}$	24-hour 1st highest	TBD	TBD	TBD	--	--
	24-hour design value[a]	TBD	TBD	TBD	35	35
	Annual average	TBD	TBD	TBD	15	15

[a] Design values for statistically-based NAAQS include the contributions of modeled sources and background concentrations:
- For 1-hour NO_2, the 3-year average of the 98[th] percentile of the distribution of daily maximum hourly concentrations;
- For 1-hour SO_2, the 3-year average of the 99[th] percentile of the distribution of daily maximum hourly concentrations; and
- For 24-hour $PM_{2.5}$, the 3-year average of the 98th percentile of the distribution of daily maximum concentrations, however, compliance with this standard has been evaluated instead based on the maximum predicted 24-hour concentration, per a screening approach recommended by EPA to account for secondary particulate emissions not modeled.

[b] Alaska rules have not net incorporated the 1-hour NAAQS for NO_2, nor followed the federal decision to remove the 24-hour and annual SO_2 NAAQS, but are expected to do so by the filing date of the GTP PSD permit application.

[Note: Table 9.2.5.3 is included as a placeholder and will be updated in the final report. A copy of the air quality impact analysis for each compressor station will be provided to appropriate agencies after completion.]

Air quality impacts will be mitigated through the use of natural gas-fired turbines and generators that are compliant with applicable NSPS. In addition, BACT will be applied to emission sources at each compressor station due to its major source classification under PSD.

TABLE 9.2.5-3

Predicted Pollutant Concentrations for Comparison with National Ambient Air Quality Standards and Alaska Ambient Air Quality Standards – Compressor Station Normal Operations

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	National Ambient Air Quality Standards ($\mu g/m^3$)	Alaska Ambient Air Quality Standards ($\mu g/m^3$)
NO_2	Maximum 1-hour design value[a,b]	TBD	TBD	TBD	188	--
	Annual average	TBD	TBD	TBD	100	100
SO_2	Maximum 1-hour design value[a]	TBD	TBD	TBD	196	196
	3-hour 1st highest	TBD	TBD	TBD	1,300	1,300
	24-hour 1st highest[b]	TBD	TBD	TBD	--	365
	Annual average[b]	TBD	TBD	TBD	--	80
CO	1-hour 1st highest	TBD	TBD	TBD	40,000	40,000
	8-hour 1st highest	TBD	TBD	TBD	10,000	10,000
PM_{10}	24-hour 4th highest	TBD	TBD	TBD	150	150
$PM_{2.5}$	24-hour 1st highest	TBD	TBD	TBD	--	--
	24-hour design value[a]	TBD	TBD	TBD	35	35
	Annual average	TBD	TBD	TBD	15	15

[a] Design values for statistically-based NAAQS include the contributions of modeled sources and background concentrations:
- For 1-hour NO_2, the 3-year average of the 98th percentile of the distribution of daily maximum hourly concentrations;
- For 1-hour SO_2, the 3-year average of the 99th percentile of the distribution of daily maximum hourly concentrations; and
- For 24-hour $PM_{2.5}$, the 3-year average of the 98th percentile of the distribution of daily maximum concentrations, however, compliance with this standard has been evaluated instead based on the maximum predicted 24-hour concentration, per a screening approach recommended by EPA to account for secondary particulate emissions not modeled.

[b] Alaska rules have not net incorporated the 1-hour NAAQS for NO_2, nor followed the federal decision to remove the 24-hour and annual SO_2 NAAQS, but are expected to do so by the filing date of the APP compressor station PSD permit applications.

9.2.6 GENERAL CONFORMITY

Promulgated under 40 C.F.R. pt. 51 Subpart W and 40 C.F.R. pt. 93 Subpart B, the General Conformity Rule applies to all federal actions except for those related to transportation plans, programs, and projects. The General Conformity Rule is used to determine if federal actions meet the requirements of the CAA and the applicable State Implementation Plan (SIP) by ensuring that air emissions related to the action do not cause or contribute to new violations of a NAAQS; increase the frequency or severity of any existing violation of a NAAQS or interim emission reduction. A SIP is an EPA-approved compilation of a state's air quality control plans and rules.

A federal action is subject to the General Conformity Rule if it is not classified as an exempt activity and if the total direct and indirect emissions of a nonattainment/maintenance pollutant (or its precursors) equal or exceed minimum thresholds established in the General Conformity regulations; or the emissions equal or exceed 10 percent of the total emissions budget for the entire nonattainment or maintenance area. If emissions are less than these criteria levels, then the federal action is presumed to conform with the SIP, and the General Conformity Rule is not applicable. Table 9.2.6-1 summarizes these thresholds for the Fairbanks nonattainment area.

TABLE 9.2.6-1

Alaska Pipeline Project
Comparison of Project Emissions to General Conformity Thresholds

Nonattainment Area	Pollutant	Estimated Construction Emissions (tons)	General Conformity Thresholds (tons)
Fairbanks North Star Borough (Fairbanks)	$PM_{2.5}$ [a]	4.8	100
	CO	26.9	100

[a] Total Project $PM_{2.5}$ emissions have been included. Annual totals will be less than the Project total; therefore, each year has not been included.

Note: Values specified as TBD will be updated for the final report.

The General Conformity Rule potentially applies to Project activities within Fairbanks (part of the Fairbanks North Star Borough $PM_{2.5}$ nonattainment and CO maintenance area). Figure 9.2.6-1 shows the Project footprint and the applicable nonattainment/maintenance area. Pursuant to 18 AAC 50.700-735, the provisions of 40 C.F.R. pt. 93, Subpart B (General Conformity Rule) is incorporated by reference into Alaska air quality rules. As none of the APP compressor stations will be constructed in nonattainment areas, only Project construction emissions will occur in the Fairbanks North Star Borough, including but not limited to, Project-related truck traffic and heavy equipment operation during construction. The construction-related emissions will be less than General Conformity threshold criteria (see Table 9.2.6-1). Therefore, the General Conformity Rule will not be applicable to APP. Sample calculations associated with construction emission estimates are presented in Appendix 9A.

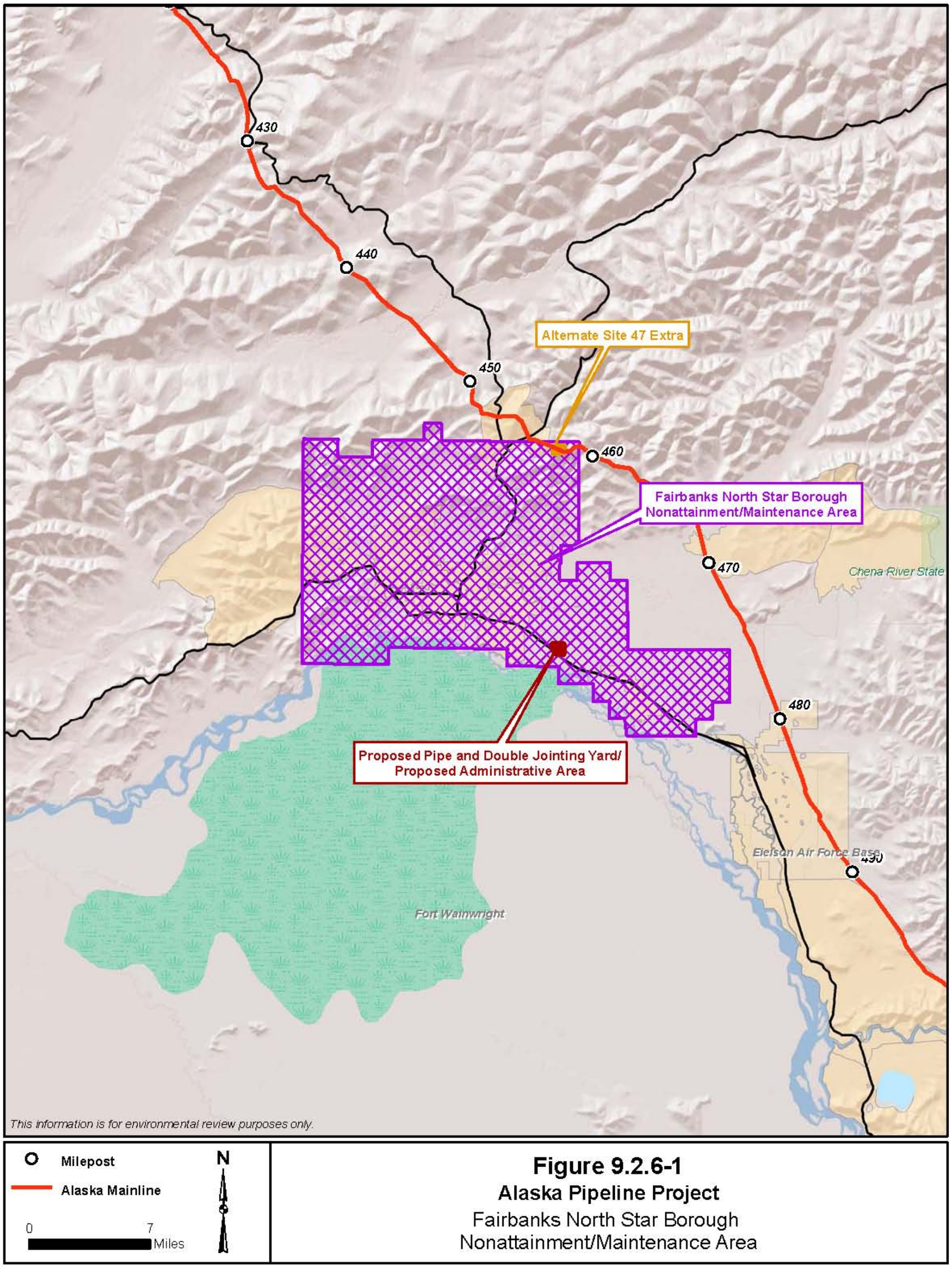

Figure 9.2.6-1
Alaska Pipeline Project
Fairbanks North Star Borough
Nonattainment/Maintenance Area

DRAFT

9.3 CLIMATE CHANGE

9.3.1 EXISTING CLIMATE CONDITIONS

The Arctic has experienced widely variable climatic conditions over the course of geologic history. The past two million years of Arctic environmental history have been characterized by a series of major glacial events and intervening warm periods (Symon et al. 2005). In recent decades, scientists have characterized the Arctic as experiencing a warming trend (Symon et al. 2005).

Climate models relied upon by the Intergovernmental Panel on Climate Change (IPCC) project more warming in the future in the Arctic compared to the rest of the world (IPCC 2007a). The IPCC has linked this predicted warming to climate change induced by emissions of GHGs. GHGs limit heat's ability to escape from Earth's atmosphere into space. The principal GHGs are CO_2, CH_4, nitrous oxide, O_3, and water vapor. The main Project-related GHG is CO_2, as it is released into the atmosphere through the burning of fossil fuels.

Several climate models and studies have linked increasing temperatures in the Arctic to a number of impacts that may be occurring, or could occur in the region, including:

- Permafrost thawing, which may pose threats to some roads and buildings and potentially contribute to eroding coastlines and increase maintenance costs in the Arctic (IPCC 2007b);
- Sea-level rise, increased storm activity, and flooding, which may threaten buildings, roads, and powerlines along low coastlines in the Arctic and, combined with thawing permafrost, cause erosion (IPCC 2007b; Weller 1998a and b);
- Changes in the thickness, persistence, and distribution of sea ice, which could have effects on marine mammal survival rates and migration routes. Potential impacts have been identified for polar bears, walruses, seals, and bowhead whales (IPCC 2007b);
- Changes in species assemblages and populations of birds and animals as a result of changes in weather patterns, sea ice, water temperatures, and other climactic and habitat changes (BESIS Project Office 1997; Environment Canada 1997; IPCC 2001; National Assessment Synthesis Team 2000; National Research Council 2003; Parmesan and Galbraith 2004; Parson et al. 2001; Russell et al. 1993; The Wildlife Society 2004; United Nations Environment Programme 2005; EPA 1998);
- Changes in vegetation patterns, with forests replacing tundra, and tundra vegetation moving into previously barren areas (IPCC 2007b);
- Decreases or increases in precipitation, which could affect local village water supplies, shift the migration patterns of land mammals, alter bird breeding and molting areas, affect the distribution and abundance of anadromous and freshwater fish, and limit or alter subsistence access routes (particularly in spring and fall) (AMAP 1997); and
- Potential reduction in the annual period that ice roads can be used (IPCC 2007b), which can lead to an increased use of permanent gravel roads. Gravel roads can contribute to the fragmentation of landscapes and habitats.

9.3.2 CONSTRUCTION AND OPERATION IMPACTS AND MITIGATION

For purposes of this resource report, APP notes that the draft Council on Environmental Quality (CEQ) guidance identifies three types of climate-related impacts for discussion: 1) the Project's contribution to climate change; 2) the Project's impact to the environment in light of potential or expected climate change sensitivities; and 3) the impact on the Project from climate change. The first type of impact requires an evaluation of the GHG emissions that will come from construction and operation of the Project. The second and third types of impacts require an evaluation of the potential or expected impacts from climate change. As discussed below, federal agencies have recently acknowledged that there are significant limitations to evaluating and reaching conclusions about any potential climate change impacts in all three categories.

9.3.2.1 Contribution to Climate Change

The total potential GHG emissions from APP operations are estimated to be about 6.1 million tpy. By comparison, a single large coal-fired electric-generation facility emits more than twice the annual GHG emissions from APP operations (EPA 1998). Estimated GHG emissions from Project construction operations activities average less than 5,000 tonnes per month per rolling 12-month period with a maximum during any one 12 month period of about 166,000 tonnes. As discussed below, the direct emissions from construction and operation of the Project will not have any discernible direct or indirect impacts. Cumulative impacts regarding climate change are addressed in Section 9.6.

Direct Effects

As several federal agencies have made clear, it is not possible to link a project's emissions to particular climatic effects. The 2010 CEQ Draft National Environmental Policy Act (NEPA) Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions states that "it is not currently useful for the NEPA analysis to attempt to link specific climatological changes, or the environmental impacts thereof, to the particular project or emissions, as such direct linkage is difficult to isolate and to understand" (CEQ 2010).

The Director of the U.S. Geological Survey similarly explained in a May 14, 2008, memorandum that "it is currently beyond the scope of existing science to identify a specific source of CO_2 emissions and designate it as the cause of specific climate impacts at an exact location." The Director cited the Climate Change Science Program Synthesis and Assessment Product 1.1 as emphasizing "fingerprint detection of GHG effects becomes more challenging at continental or sub-continental scales." Similarly, on October 3, 2008, EPA sent a letter to the U.S. Fish and Wildlife Service (FWS) and to the National Marine Fisheries Service stating:

> "GHG emissions from single sources are small relative to aggregate emissions, and GHGs, once emitted from a given source, become well mixed in the global atmosphere and have a long atmospheric lifetime. The climate change research community has not yet developed tools specifically intended for evaluating or quantifying end-point impacts attributable to the emissions of GHGs from a single source, and we are not aware of any scientific literature to draw from regarding the climate effects of individual, facility-level GHG emission."

Further, the Department of the Interior (DOI) issued a guidance document – relying on both the U.S. Geological Survey memo and the EPA letter – that addressed "direct effects," "indirect effects," and "cumulative effects" for purposes of evaluation effects on listed species or critical habitat (DOI 2008). DOI concluded that "there will be no direct effect in the form of climate change" from GHG emissions from any project. DOI explained that:

> "The requisite causal connections cannot be made between emissions of GHGs from a proposed agency action and specific localized climate change as it impacts listed species or critical habitat. Given the nature of the complex and independent processes active in the atmosphere and the ocean acting on GHGs, the causal link simply cannot currently be made between emissions from a proposed action and specific effects on a listed species or critical habitat. Specifically, science cannot say that a tiny incremental global temperature rise that might be produced by an action under consideration would manifest itself in the location of a listed species or its habitat. Similarly, any observed climate change effect on a member of a particular listed species or its critical habitat cannot be attributed to the emissions from any particular source." (DOI 2008).

DOI also cited to an exercise where EPA modeled GHG emissions that were 20 percent greater than the emissions estimates from one of the largest proposed coal-fired electric-generating facilities in the United States. EPA analyzed the potential impact of such emissions on polar bears in the Arctic and coral off the Florida coast. EPA and DOI characterized the modeled changes from the project as "extremely small":

> "The best available climate change modeling tools predict that a source with GHG emissions equal to or less than those of the model facility analyzed above will have at most an extremely small impact on average global temperature and global atmospheric CO_2 concentrations over and beyond the anticipated functional lifetime of the proposed source. Regional modeling and any associated downscaling calculations to predict effects at a specific species location introduce untested approaches and additional uncertainties. It is clear that any such temperature and ocean acidification outputs, or any specific impact on the corals or polar bears, would be too small to physically measure or detect in the habitat of these species. Given the very small global mean climate change magnitudes projected based on the emissions of this type of single source, we believe the outputs of such a single-source impact analysis for other species in other locations would also be of an extremely small magnitude that is too small to physically measure or detect."

The hypothetical large coal-fired electric utility that EPA modeled emits more than twice the estimated GHG emissions of APP. EPA determined that the coal-fired electric utility did not cause a change in climate that could show a discernible impact on species or habitat.

Thus, consistent with approaches expressed by the FWS, EPA, and CEQ, as well as DOI's Bureau of Ocean Energy Management (BOEM) and the Department of State (DOS), as discussed below, the direct emissions from construction and operation of APP will not have any discernible direct effects on climate change.

Indirect Effects

As with direct effects, agencies have concluded that it is not possible to link "indirect effects" to a particular project. Since "indirect effect" must be "reasonably certain to occur" and must be caused by the project, the various guidance discussed above concludes that GHG emissions from a particular project cannot be linked to potential indirect effects.

To-date, no government agencies have mandated an analysis of downstream impacts from energy consumption in similar projects. In recent Final Environmental Impact Statements (EISs) for other oil and gas projects, DOS and BOEM have addressed the issue of evaluating environmental and economic impacts of GHG emissions from downstream oil and gas consumption that might be enabled by the proposed actions. In the Final Supplemental EIS for the Sale 193 (Oil and Gas Leases in the Chukchi Sea), BOEM stated that such effects from consumption of oil and gas are not effects of the Sale 193:

> "GHG emissions from consumption are not direct effects under NEPA because they do not occur at the same time and place as the action. They are also not indirect effects because Sale 193 would not be a proximate cause of greenhouse gas emissions resulting from consumption. Also, because the impacts of consumption are not direct or indirect effects of the proposed action, a cumulative impact analysis would not reveal an incremental or cumulative effect attributable to the decision to affirm, modify, or cancel the lease sale."

In the Final EIS for the Keystone XL Project, without stating that such requirement was mandated by NEPA, the DOS responded to concerns expressed by commenters about the indirect GHG impacts from not only the production of oil to be transported in the pipeline, but also the refining of the oil, and the ultimate consumption of refined products proposed to be transported by that project (DOS 2011). DOS stated that the Keystone XL Project would not substantially influence the rate or magnitude of oil production in Canada, or the overall volume of crude oil transported to or refined in the United States. In order to respond to commenters' concerns, DOS also provided lifecycle emissions associated with the oil associated with the project, concluding that the crude oil that the Keystone XL Project would transport was on average more GHG-intensive than the crudes that they might displace in the United States refineries, however, DOS also concluded that the gap in GHG intensity in these crudes might decrease over time.

Similar to the Keystone XL Project and the Sale 193, it is difficult to predict and calculate the change in production and consumption of natural gas that can be associated with APP. Federal agencies have acknowledged that changes or increases in production and consumption of natural gas are driven by a variety of complex interacting factors, including energy costs, energy efficiency, availability of other energy sources, economics, demography, and weather and climate. Furthermore, complicating the analysis is a consideration of what other fuels any increase in natural gas usage would displace, and a comparison of the relative lifecycle of gas and the other fuels. Thus, under NEPA and Endangered Species Act (ESA), the effects from increased natural gas production and consumption are not required to be analyzed as indirect effects from APP.

Although such analysis is not mandated, for purposes of this resource report, the following is an analysis similar to that provided for the Keystone XL Project EIS. It addresses the relative GHG-intensity for natural gas that will be made available and transported by this Project that would displace other fuels. The U.S. Department of Energy (DOE) describes natural gas as the least carbon-intense fossil fuel (DOE and EPA 2000). The U.S. Energy Information Agency and EPA report the CO_2 emissions per billion Btu of energy input for natural gas to be 117,000 pounds, compared to oil, which is 164,000 pounds, and 208,000 for coal. Although it is difficult or impossible to project the amounts of fuels that might be displaced by natural gas, a report released in June 2010 by the Massachusetts Institute of Technology concludes that in the short-term in the United States, natural gas could displace coal-fired power to reduce CO_2 emissions by about 20 percent at a cost of less than $20 per ton of CO_2 avoided. The report concludes that displacement of coal-fired power by gas-fired power over the next 25 to 30 years is the most cost-effective way of reducing CO_2 emissions in the power sector. This displacement would also significantly reduce pollutants such as SO_2, NO_x, particulates, and mercury. The report concludes that the power sector is the one most immediately affected by the availability of natural gas, but concludes that other sectors, such as the transportation sector and residential, industrial, and commercial energy consumers could benefit from increased availability of natural gas resulting in further CO_2 emission reductions.

Considering the potential displacement of higher carbon-intense fuels by natural gas made available by this Project, the net indirect emission benefits from this Project are expected to more than offset the total direct GHG emissions from the Project.

9.3.2.2 Sensitive Areas

CEQ's 2010 draft guidance proposes that agencies evaluate how climate change could influence, effect or otherwise change environmental impacts of the Project. CEQ suggests that "climate change can increase the vulnerability of a resource, ecosystem, or human community, causing a proposed action to result in consequences that are more damaging than prior experience with environmental impacts analysis might indicate." If FERC decides to follow that draft guidance, APP notes that CEQ limits such analysis to effects that have "a reasonably close causal relationship between the environmental effect and the alleged cause." To the extent that climate change impacts on a resource are reasonably foreseeable and APP can identify its additional impact on that resource, the issue is discussed in the relevant resource report.

9.3.2.3 Impact on the Project

If increases in Arctic temperatures predicted by some climate models relied upon by the IPCC ultimately come to pass, those changes have the potential to impact the Project and thus are being considered in Project design. Notably, changing temperatures may change the frost heave and thaw that the pipeline is subjected to, as well as potential right-of-way settling. These changes may increase (or potentially decrease) strain on the pipeline.

In designing the pipeline, APP has accounted for potential change by modeling the impact of a warming trend in Alaska and ensuring that the pipeline is designed to accommodate any resulting settling or strain.

Similarly, APP increased the work pad thickness at the GTP to 6 feet, whereas designs done in the early 1970s used 5 feet. This is intended to address the potential increase in average thaw depths and to prevent thaw-settlement.

9.4 NOISE

This section describes the existing noise environment and assesses the potential noise impacts of APP (construction and operation) on the surrounding environment.

At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week. This variation is caused in part by changing weather conditions, but also by the effects of seasonal groundcover and other activity. Three measures used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the 24-hour equivalent sound level

($L_{eq(24)}$), the day-night sound level (L_{dn}), and the night sound level (L_n). The $L_{eq(24)}$ is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The L_{dn} is the $L_{eq(24)}$ with 10 decibels of the A-weighted scale (dBA) added to the nighttime sound levels between the hours of 10 p.m. and 7 a.m. to account for people's greater sensitivity to sound during nighttime hours. The L_n is the sound level between 10 p.m. and 7 a.m. For continuous noise sources, the L_n is equal to the $L_{eq(24)}$.

9.4.1 REGULATORY REQUIREMENTS

9.4.1.1 Federal

In 1974, EPA published "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety." This publication evaluated the effects of environmental noise with respect to health and safety. EPA has determined that noise levels should not exceed an L_{dn} of 55 dBA for these types of activities. This noise level is commonly used by federal and state agencies to establish noise limitations for cumulative noise exposure. With a 10 dBA nighttime weighting penalty, a 55 dBAL_{dn} noise level equates to a 24-hour continuous noise level of 49 dBA$L_{eq(24)}$ (i.e., a facility that does not exceed a continuous noise impact of 49 dBAL_{eq} would not exceed 55 dBAL_{dn}). FERC limits the noise attributable to stationary energy facilities (such as compressor stations) to 55 dBAL_{dn} at noise-sensitive areas (NSAs) such as schools, hospitals, or residences. APP will comply with FERC standards to limit noise impacts at NSAs near the GTP and compressor stations.

9.4.1.2 State

The State of Alaska has not adopted noise regulations applicable to the Project.

9.4.1.3 Local

Portions of APP will be located within the North Slope Borough, the Yukon-Koyukuk Census Area, the Fairbanks North Star Borough, and Southeast Fairbanks Census Area. None of these local jurisdictions have adopted noise regulations applicable to the Project.

9.4.2 CONSTRUCTION AND OPERATION IMPACTS AND MITIGATION

In order to evaluate impacts of construction and operation, APP will conduct summer and winter 24-hour L_{dn} noise measurement surveys to quantify the existing baseline noise environment.

Noise associated with Project activities includes long-term operational noise and temporary noise associated with Project construction. Operational noise is primarily associated with GTP and compressor stations. Construction noise of varying magnitude and duration will occur at all Project locations.

The Project environs encompass various noise environments from the relatively loud existing industrial environment in the vicinity of the GTP, suburban and urban residential areas, and the natural quiet of sparsely developed area associated with the pipeline. Project design and acoustical mitigation (as applicable) will ensure that in all environments the Project will comply with all applicable federal, state, and local laws and regulations pertaining to noise exposure.

9.4.2.1 Construction

The most prevalent sound source during construction is anticipated to be the internal combustion engines used to provide mobility and operating power to construction equipment and noise exposure from piling and dredging activities. Short-term noise emissions associated with HDD entry and exit sites and blasting activities will also be analyzed. The sound level impacts at NSAs associated with the HDD entry and exit sites from construction operations will depend on the type of equipment used, the mode of operation of the equipment, the length of time the equipment is in use, the amount of equipment used simultaneously, and the distance between the sound source and sensitive site. Noise impacts to wildlife will be addressed in Resource Report 3 upon completion of the detailed reports and consultation with the appropriate agencies. Blasting and HDD activities may be required in areas where NSAs are located. APP will determine the location of all HDD sites and determine the noise impacts of these locations to NSAs. All blasting will be done in accordance with APP's Blasting Plan (refer to the outline of the Blasting Plan provided in Appendix 6B of Resource Report 6).

Gas Treatment Plant

Construction of the GTP is expected to generate noise, primarily during the initial phases when blasting, roadway, pad construction, and installation of piles and vertical support members are underway, and during the summer months when facility modules and other equipment will be delivered and set in place. Ambient noise monitoring to quantify existing noise levels and modeling to quantify GTP construction noise emissions are currently in development. Detailed reports will be provided upon completion. There are no existing noise-sensitive land uses (residential, schools, hospitals, etc.) anywhere near the GTP site.

Primary sources associated with GTP construction are noise from on-site mechanical equipment used to prepare the site for operation, and noise from trucks and barges used to get the equipment and materials on site. These sources will include bulldozers, graders, excavators, front-end loaders, backhoes, cranes, trucks, barges, and other vehicle traffic. Materials will be transported by truck over the Dalton Highway and access roads in the area of the Project site. Barges will be used during the open-water season to transport facility modules and other equipment to the site.

Typical Compressor Station

Construction of the compressor stations will involve clearing and grading, placement of fill, and pilings for foundations for the compressor unit packages, other equipment settings, and ancillary equipment, associated unit housing, piping, and structures. Site selection for the compressor stations is ongoing. Proximity to NSAs is a consideration in the site selection process. Compressor station construction noise levels at NSAs will be determined following site selection.

Pipeline Construction

The Project consists of 15 Alaska Mainline segments (spreads) and one spread for the PT Pipeline. Construction of each segment can be thought of as a moving production line and may last five to six months. However, the activities that will be most intense during pipe installation and involve the most equipment will be during production welding and lowering-in. The dominant noise sources that will be operating at each of the pipeline spreads during the duration of construction are the generators. Other noise sources include heavy equipment. Construction equipment will be operated on an as-needed basis during pipeline construction. While individuals in the immediate vicinity of the construction activities will experience an increase in noise, this effect will be temporary and local. Proximity of NSAs to pipeline construction activities will be evaluated.

Horizontal Directional Drilling Operations

APP is considering using the HDD crossing method at various locations along the pipeline route. Once HDD equipment and anticipated noise levels can be ascertained, an analysis of potential noise impacts at NSAs will be undertaken to identify if mitigation measures are necessary to reduce the potential noise impact of the HDD operations.

The largest amount of equipment and the most noise will be located at the entry side of the HDD construction site. Typical equipment located at the HDD entry site will include:

- Drilling rig and associated engine-driven hydraulic power unit;
- Mud pump(s);
- Generator(s);
- Compressor(s);
- Crane(s), boom truck(s), loader(s), backhoe, and/or forklift; and
- Engine-driven light plants (for nighttime operation).

Anticipated equipment at the exit site will include:

- Backhoe, sideboom(s), crane(s), and generators; and
- Engine-driven light plants (for nighttime operation).

Due to the unique nature of HDD activities, 24-hour operations at HDD sites, and the proximity of NSAs, the following measures may be employed, as needed, to mitigate HDD noise impacts:

- Develop site-specific noise mitigation plans to comply with any specific regulations and obtain any applicable authorizations or variances, if local noise regulations exist;
- Provide noise mitigation plans to the construction contractors for implementation and enforcement by construction inspectors using approved portable sound meters;
- Give advance notice to landowners prior to construction;
- Use best available noise control techniques such as mufflers, intake silencers, ducts, engine closures, and acoustically attenuating shields or shrouds for construction equipment and trucks;
- Coordinate work schedules to the extent practicable to reduce disruption in residential areas;
- Set up a toll-free telephone line for landowners to report any construction noise-related issues;
- Perform a noise assessment survey during operations in locations where nearby residents express concerns about noise;
- Construct berms or place screens around the equipment as noise abatement measures, if needed; and
- Use temporary equipment enclosures supplemented with insulation or other suitable noise attenuation barrier as required.

Because the selection of HDD locations is preliminary, any identified mitigation measures required by the site-specific detailed modeling will be added to the final site-specific crossing plans for the HDDs.

9.4.2.2 Operations

EPA has determined that noise levels should not exceed an L_{dn} of 55 dBA. This noise level has been useful for federal and state agencies to establish noise limitations for long-term, continuous noise sources. A 55 dBAL_{dn} noise level equates to an $L_{eq(24)}$ of 49 dBA (i.e., a facility that does not exceed a continuous noise impact of 49 dBA would not exceed 55 dBAL_{dn}). FERC limits the noise attributable to stationary energy facilities (such as compressor stations or GTPs) to 55 dBAL_{dn} at NSAs.

Gas Treatment Plant

No NSAs have been identified within 1 mile of the GTP. Ambient noise monitoring to quantify existing noise levels, and modeling to quantify GTP operational noise emissions, are currently in development. Detailed reports along with an updated list of impacted NSAs and appropriate mitigation, if deemed necessary, will be provided upon completion.

Compressor Stations without Known Noise-Sensitive Areas

No NSAs have been identified within 1 mile of the Happy Valley, Galbraith Lake, Chapman Creek, Fort Hamlin Hills, Johnson Road, or Tetlin Junction Compressor Stations. APP will develop a monitoring and modeling program to identify the potential noise impact associated with compressor station operations at each location. The impact contours will determine the radius out to which each individual compressor station will emit sound levels at 55 dBAL_{dn}. APP will then utilize this information to determine if any NSAs are present within the impacted area and will determine the appropriate mitigation measures, if deemed necessary.

Tatalina River Compressor Station

Table 9.4.2-1 lists the potential APP identified NSAs for the Tatalina River Compressor Station.

TABLE 9.4.2-1

Alaska Pipeline Project
Sound Level Contributions to Noise-Sensitive Areas near the Tatalina River Compressor Station

Noise-Sensitive Areas	Distance to Compressor Building (feet)	Direction	Measured Ambient L_d	Calculated Ambient L_{dn}	Estimated L_{dn} of Station	Station L_{dn} + Ambient L_{dn}	Potential Increase Above Ambient
NSA #1 (residence)	~5,200	SSW	TBD	TBD	TBD	TBD	TBD
NSA #2 (residence)	~5,200	SSW	TBD	TBD	TBD	TBD	TBD
NSA #3 (residence)	~5,200	SSW	TBD	TBD	TBD	TBD	TBD

Values specified as TBD will be updated for the final report.

Ambient noise monitoring is scheduled to begin at known NSAs in the 2012 field season. Results of the monitoring along with calculated impacts from the station operation, including any identified mitigation, will be included upon completion.

George Lake Compressor Station

Table 9.4.2-2 lists the potential APP-identified NSAs for the George Lake Compressor Station.

TABLE 9.4.2-2

Alaska Pipeline Project
Sound Level Contributions to Noise-Sensitive Areas near the George Lake Compressor Station

Noise-Sensitive Areas	Distance to Compressor Building (feet)	Direction	Measured Ambient L_d	Calculated Ambient L_{dn}	Estimated L_{dn} of Station	Station L_{dn} + Ambient L_{dn}	Potential Increase Above Ambient
NSA #4(residence)	1,580	NE	TBD	TBD	TBD	TBD	TBD
NSA #5 (residence)	2,325	SE	TBD	TBD	TBD	TBD	TBD
NSA #6 (residence)	2,325	SE	TBD	TBD	TBD	TBD	TBD

Values specified as TBD will be updated for the final report.

Ambient noise monitoring is scheduled to be completed at the identified NSAs in the 2012 field season. Results of the monitoring, along with calculated impacts from the station operation, including any identified mitigation, will be included upon completion.

Miscellaneous Aboveground Facilities

Helicopters may be used periodically to conduct flyover inspections of the pipeline in accordance with U.S. Department of Transportation Minimum Federal Safety Standards (49 C.F.R. pt. 192). Helicopter operations have the potential to significantly increase noise exposure. It is anticipated that pipeline maintenance activities will occur during daytime hours, be of relatively short duration, and present highly localized noise exposure. Helicopter operational activity is not yet defined. Noise analysis of helicopter operations will be conducted when a representative fleet mix, number of operations, operational periods and generalized flight paths have been determined.

During operation there may be short-term noise impacts from aboveground Pipeline Facilities[8] (e.g., mainline block valves) or from vehicles and equipment performing routine maintenance. Temporary noise impacts will result from the infrequent blowdowns at mainline block valves or compressor stations. Blowdown events involve the evacuation of gas from piping, which enables piping to be taken out of service, typically for major repairs or maintenance. APP will develop a mitigation plan, to minimize impact to surrounding residences and other NSAs as necessary and in accordance with the appropriate regulations. Blowdown events are infrequent and typically last for a short period of time. As such, the noise from blowdown events during operation of the APP facilities will not cause significant noise impacts.

Noise events associated with facility start-up, shutdown, and upset conditions may result in significant, but temporary, increase in noise levels. Noise exposure from these conditions is anticipated to be of very short duration and will have little effect in terms of cumulative noise metrics such as L_{dn}.

9.5 CUMULATIVE IMPACTS

[Note: Field surveys and agency consultation are ongoing. Cumulative impacts will be updated in the final report.]

8 The Pipeline Facilities will consist of the PT Pipeline and the Alaska Mainline, as discussed in Section 1.3.1 of Resource Report 1.

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