United States Department of the Interior
Bureau of Land Management

Environmental Assessment for the Twentymile Coal Lease Modification

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BLM

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U.S. Department of the Interior
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ENVIRONMENTAL ASSESSMENT

Chapter 1 – Introduction

1.1 Identifying Information

EA-Number: DOI-BLM-N010-2012-0040EA

Permit/Lease Number: COC72980

Project Name: Twentymile Coal 40 acre Lease Modification

Legal Description: T. 5 N., R. 87 W., 6^{th} P. M.; sec. 34, NW¼NE¼

Applicant: Twentymile Coal, LLC

1.2 Background Information

Peabody Energy's Twentymile Coal, LLC (Twentymile Coal) has submitted a lease modification to the Bureau of Land Management (BLM) seeking to modify an existing coal lease, COC72980. The lease modification is for 40 acres of un-leased federal mineral estate under private lands located adjacent to Twentymile Coal's currently operating coal mine (the Foidel Creek Mine). It is estimated that the federal coal reserves included in this lease modification would total approximately 644,000 recoverable tons of high volatile, group B, bituminous Wadge seam coal.

Coal has been mined in Routt County for almost 100 years. Twentymile Coal has been mining at the Foidel Creek by underground methods since 1982. Coal is a federal asset, and the Bureau of Land Management (BLM) is required by law to consider leasing federally owned minerals for economic recovery. (*See* Mineral Leasing Act (MLA) of 1920, as amended by the Federal Coal Leasing Amendments Act (FCLAA) of 1976; Federal Land Policy and Management Act (FLPMA) of 1976; and, 43 C.F.R § 3400, et seq.) The decision to lease these lands is a necessary prerequisite for mining, but it does not authorize mining. If the BLM decides to lease the federal coal described in the lease modification submitted by Twentymile Coal, the fair market value (FMV) of the coal would be determined and Twentymile Coal would submit payment for the 644,000 tons of coal. If the coal is mined, Twentymile Coal would pay 8% royalties on sales of the coal. Twentymile Coal must submit a plan for mining and reclamation to the Department of the Interior, Office of Surface Mining Reclamation and Enforcement (OSM), for review and approval. Once a mining plan has been submitted, OSM would review the developments proposed in the mining plan.

Twentymile Coal holds a coal mining permit with the Colorado Division of Reclamation, Mining and Safety (DRMS). This permit was issued in 1982. The permit encompasses 19,940 acres. The 40 acre lease modification would increase the permit by 40 acres (0.2%). Twentymile Coal would need to modify their permit to include the 40 acre lease modification.

This lease modification involves leasing underground federal coal reserves beneath private lands. Twentymile Coal owns the surface of the 40 acres. The surface facilities for the mine are located on private land approximately 4 miles from the lease modification. The coal to be mined from the 40 acres covered by this lease modification would be processed at the existing Twentymile Coal Company Foidel Creek Mine surface facilities. The only potential surface disturbance from mining the coal in this lease modification would be as a result of subsidence.

Leasing of the 40 acres would enable Twentymile Coal to lengthen two longwall panels and provide a logical extension of Twentymile Coal's development of the Wadge seam. Twentymile Coal would be able to maximize recovery of federal coal – if the federal coal in question is not mined by Twentymile Coal it would be bypassed and the potential economic recovery would be lost. Mining of the lease modification would occur over a two year period approximately, and would allow Twentymile Coal to continue to employ the workforce for the additional time required to extract the coal.

The development of this coal reserve is important to both the local economy and the nation. If leased, the coal would likely be used for electrical power generation, but may be used for other industrial purposes. According to the Energy Information Administration, coal is currently used for about 50 percent of the total generation in the electric power sector. Leasing the coal allows development of federal coal resources to meet the public's continuing economic demands for dependable and affordable domestic energy while giving due consideration to the protection of other resource values. As a result of the leasing and probable subsequent mining and sale of federal coal resources, the public receives lease bonus payments, lease royalty payments, and a reliable supply of low sulfur coal for power generation.

Unsuitability criteria apply only to surface coal mining, and therefore are not applicable for this lease modification.

1.3 BLM's Purpose/Need for the Proposed Action:

The Proponent, Twentymile Coal, has applied for a coal lease modification to the federal coal lease COC-72980 immediately adjacent to the existing Foidel Creek Mine so that Twentymile Coal can continue to supply and sell coal. BLM is preparing this EA in response to the request by Twentymile Coal for this coal lease modification.

1.31 Purpose:

The BLM's purpose is to decide whether to lease the coal as applied for, reject the application, or modify the proposed lease tract in response to the application to modify the federal coal lease COC-72980.

1.32 Need:

The BLM's need is to respond to a request to modify an existing lease in accordance with the National Environmental Policy Act (NEPA), the MLA of 1920, as amended by the FCLAA of 1976, and the FLPMA of 1976.

1.4 Land Use Plan Conformance:

The Proposed Action was reviewed for conformance (43 CFR 1610.5, BLM 1601.3) with the following plan:

Name of Plans: Little Snake Record of Decision and Resource Management Plan (RMP)

Date(s) Approved: October, 2011

Results: The Proposed Action is in conformance with the LUP because it is specifically provided for in the following LUP goals, objectives, and management decisions as follows:

Allow for the availability of the federal coal and oil shale estate for exploration and development. Objectives for achieving these goals include:

- Identify and make available the federal coal and oil shale estate for exploration and development, consistent with appropriate suitability studies, to increase energy supplies.
- Facilitate reasonable, economical, and environmentally sound exploration and development of the federal coal and oil shale estate.
- Promote the use of BMP's, including implementation of sound reclamation standards.

Section/Page: RMP-36

1.5 Scoping and Public Involvement and Issues: This project was circulated for external scoping by posting the action in this EA on LSFO NEPA register from May 2, 2012 to present:

http://www.blm.gov/co/st/en/BLM_Information/nepa/lsfo.html.

The LSFO received no comments during external scoping. Resources identified by internal scoping are brought forward for analysis in this EA.

No one requested to be an interested party.

Chapter 2 Description of Proposed Action and Alternatives:

2.1 Proposed Action

The Proposed Action is to modify Twentymile Coal's existing federal coal lease COC72980 by adding approximately 40 acres according to the MLA. There would be no surface facilities on the 40 acre surface. The lease modification would enable additional coal reserves to be mined by longwall methods, which maximizes recovery of the coal resource and provides the United States Government with income from the sale of the lease modification and from royalties of the mined coal. The estimated amount of recoverable coal in the lease modification is 644,000 tons (Combined Geologic Engineering Report and Maximum Economic Recovery Report for Twentymile Coal Lease Modification COC72980).

The 40 acre tract is to the south of federal coal lease COC72980. These 40 acres of Wadge seam coal are surrounded on three sides by privately owned minerals. The Wadge seam coal would be bypassed if this lease modification is not approved as it cannot be accessed from any other locations due to geologic conditions, coal ownership, and the proximity of current and future underground mining.

2.2 No Action Alternative

In accordance with the NEPA and the Council on Environmental Quality (CEQ) regulations, which require a No Action Alternative be presented in all environmental analyses in order to serve as a "base line" or "benchmark" from which to compare all proposed "action" alternatives, the No Action Alternative is analyzed in this Environmental Assessment (EA).

Under the No Action Alternative, BLM would not approve the modification. As a result, federal coal reserves within the Twentymile Coal modification would not be recovered and would, therefore, be bypassed. Production at the Foidel Creek Mine would eventually cease once coal reserves under existing leases were mined.

2.3 Alternatives Considered but Eliminated from Detailed Analysis:

If an alternative is considered during the environmental analysis process, but the agency decides not to analyze the alternative in detail, the agency must identify those alternatives and briefly explain why they were eliminated from detailed analysis (40 CFR 1502.14). An action alternative may be eliminated from detailed analysis if:

- it is ineffective (does not respond to the Purpose and Need for the Proposed Action);
- it is technically or economically infeasible (considering whether implementation of the alternative is likely, given past and current practice and technology);
- it is inconsistent with the basic policy objectives for the management of the area [such as, not in conformance with the Resource Management Plan (RMP)];
- its implementation is remote or speculative;
- it is substantially similar in design to an alternative that is analyzed; and/or
- It would result in substantially similar impacts to an alternative that is analyzed.

Alternatives specific to this EA that were considered, but that will not be analyzed in detail, are discussed below.

2.31 Methane Capture

An alternative to capture the coal mine methane (CMM) from the mining of the additional 40 acres of the Wadge coal seam was considered, but eliminated from detailed analysis because it is technically infeasible and its implementation is remote or speculative. These obstacles include technical challenges, unresolved legal issues concerning ownership of the coalbed methane resource, power prices, and pipeline capacity, quantity of gas, and quality constraints.

All of the methane from the 40 acre lease modification and from the mine can be vented through the mine ventilation system efficiently. Twentymile does not use degasification wells because the methane concentrations are low and can be vented through the existing mine ventilation system to keep concentrations within Mine Safety and Health Administration (MSHA) regulations. Additionally, a degasification well would require surface disturbance, which would cause environmental impacts. There is no surface disturbance associated with the proposed action. Currently, there are more than 1,000 underground coal mines in the U.S. There are presently only 15 coal mine methane recovery and utilization projects at active underground coal mines (Environmental Protection Agency (EPA) Coalbed Methane Outreach Program (CMOP), 2011). Twentymile Coal is not a gassy mine and was not identified as a candidate for methane recovery in the CMOP report.

Practical constraints on commercial development of methane or natural gas in this area include the depth of the resource, the occurrence of the resource, resource quality and quantity, and limitations relative to effective resource development and production and the mine life.
EPA's Identifying Opportunities for Methane Recovery at U.S. Coal Mines, Revised 2009 states:

> "Life expectancy refers to the number of years left in the mine's plan for mining coal; it can be an important factor in determining whether a mine is a good candidate for a methane recovery and use project."

Prediction of mine life is difficult and speculative. Currently, Twentymile expects to mine for 5 more years. Mining of the 40 acre lease modification is estimated to occur over a 2 year period. With respect to resource quality and quantity, methane liberation and resulting concentrations from the Wadge coal seam are low, and any methane released is further diluted by mine ventilation air, with the result that the concentration of any methane discharge from mining operations (as a component of ventilation exhaust air) is so low that it renders collection and concentration of the resource for sale and use practically infeasible. Even if collection and concentration were feasible, a network of collection pipelines, compressors and storage tanks would be necessary to collect, store, and transport the methane.

Since there is no gas transmission pipeline in the immediate area, the gas would have to be trucked from a central temporary storage point to either a pipeline transfer point or gas processing plant. A market for the gas would also have to exist. Only high quality gas (>95% methane) can be used for pipeline injection, if a pipeline existed. The economic viability of capturing the gas is limited due to the quantity and quality of the gas and the infrastructure required for distribution. Technologies for Ventilation Air Methane (VAM) Capture are still in the developmental stage and cost information is still limited (EPA CMOP, 2011).
Therefore, the implementation of methane capture is unlikely, given past and current practice and technology.

2.32 Methane Flaring

The alternative to flare the methane created by mining an additional 40 acres of the Wadge coal seam was also considered and eliminated from detailed analysis. BLM determined it to be technically or economically infeasible and its implementation is remote and speculative. About 29 U.S. coal mining operations use vertical methane drainage wells to vent gas from the mines. In all cases, gas vented from these wells is discharged directly into the atmosphere. Under ideal conditions, operators would collect methane gas directly at the wellhead for sale or on-site use. Because of variable gas quality and quantity, difficulties in coordinating commercial gas recovery with underground mine degasification requirements, and the economics of commercializing methane mixed with air, coal mine operators commonly vent methane to the atmosphere and do not capture the gas.

In these cases, safety and environmental objectives could be satisfied by carefully flaring emitted gas. Gas flaring is a standard safety practice in some industries. For example, methane and other associated gases are routinely flared during processing and production of oil and gas, and are continuously flared from landfill collection systems. Incorporating a controlled flare system could minimize the potential of an unconfined conflagration occurring on the surface at the methane drainage discharge location(s) and would potentially reduce greenhouse gas effects through combustion of the associated hydrocarbons.

The Environmental Protection Agency is currently sponsoring research and outreach efforts to coal mine operators to encourage coalbed and coal mine methane capture or flaring (refer to www.epa.gov/coalbed). The methodology for flaring methane emissions from underground coal mines is emerging, but remains technologically speculative at this time. The hazard that flaring could create relative to the potential for an underground ignition has not been clearly dismissed by current technology. MSHA does not have regulations that would govern this activity, but has expressed concerns relative to safety with respect to the potential for propagation of fire through methane drainage boreholes into underground mines. MSHA would not approve flaring without significant preliminary testing to assure the safety of the miners; therefore flaring would not be practicable. There would also be an associated potential fire hazard where flammable brush, trees, or other vegetation exists in close proximity to the wellhead. The BLM does not have a policy governing flaring of gas from coal mining operations, so the issue of whether or not a gas lease would be required is unclear. These outstanding questions would have to be resolved if flaring is considered as an alternative to discharging methane into the atmosphere.
Additionally, flaring of methane would result in the release of other air pollutants, including nitrogen oxides, carbon dioxide, and carbon monoxide; these pollutants are regulated by the EPA for national ambient air quality standards. Methane is not a regulated gas. Therefore, the implementation of methane flaring is unlikely, given past and current practice and technology.

FIGURE 1: MAP OF THE LEASE MODIFICATION AREA

CHAPTER 3 – AFFECTED ENVIRONMENT AND EFFECTS

3.1 INTRODUCTION

Affected Resources:
The CEQ Regulations state that NEPA documents "must concentrate on the issues that are truly significant to the action in question, rather than amassing needless detail" (40 CFR 1500.1(b)). While many issues may arise during scoping, not all of the issues raised warrant analysis in an EA. Issues will be analyzed if: 1) an analysis of the issue is necessary to make a reasoned choice between alternatives, or 2) if the issue is associated with a significant direct, indirect, or cumulative impact, or where analysis is necessary to determine the significance of the impacts. Table 1 lists the resources considered and the determination as to whether they require additional analysis.

Table 1. Resources and Determination of Need for Further Analysis

Determination[1]	Resource	Rationale for Determination
Physical Resources		
PI	Air Quality and Climate	See Section 3.2.1
NI	Floodplains	There is a frequently flooded FEMA-identified 100-year floodplain on private surface along Fish Creek, a perennial stream that is adjacent to the 40-acre parcel proposed as part of this lease modification. However, neither alternative includes development within the floodplain. No threat to human safety, life, welfare and property will result from implementing either of the alternatives, so analysis is not carried forward.
PI	Hydrology, Ground	See section 3.2.8
NI	Hydrology, Surface	Surface hydrology is unlikely to be impacted as a result of the potential leasing and development of the proposed parcel since all activity would occur below ground.
NI	Minerals, Fluid	The nearest producing well is located in Section 20, T5N, R87W. The proposed action would cause no effect on fluid minerals. Several wells have been both plugged and abandoned or drilled and abandoned in T5N, R87W and T4N, R87W.
PI	Minerals, Solid	See section 3.2.4
NI	Soils	All activity as part of the lease modification occurs underground - no activity that disturbs or modifies soils is proposed. Surface ownership above the coal lease is private.
PI	Water Quality, Ground	See Section 3.2.8
NI	Water Quality, Surface	Surface water quality is unlikely to be impacted as a result of the potential leasing and development of the proposed parcel since all activity would occur below ground. Surface discharge of any groundwater encountered during the mining process is not proposed.
Biological Resources		
NI	Invasive, Non-native Species	All activity as part of the lease modification occurs underground - no activity that disturbs or modifies invasive, non-native species is proposed. Surface ownership above the coal lease is private.

Determination[1]	Resource	Rationale for Determination
NP	Migratory Birds	This resource is not present within the proposed project area.
NP	Special Status Animal Species	This resource is not present within the proposed project area.
NP	Special Status Plant Species	This resource is not present within the proposed project area.
NP	Upland Vegetation	This resource is not present within the proposed project area.
NP	Wetlands and Riparian Zones	This resource is not present within the proposed project area.
NP	Wildlife, Aquatic	This resource is not present within the proposed project area.
NI	Wildlife, Terrestrial	All activity of the lease modification occurs underground. No activity that impacts terrestrial wildlife is proposed.
NP	Wild Horses	This resource is not present within the proposed project area.
Heritage Resources and the Human Environment		
NP	Cultural Resources	The area of potential effect has been inventoried for cultural resources. No resources which would require mitigation (those eligible for the National Register) were identified. The proposed undertaking will have no effect on cultural resources.
NP	Environmental Justice	According to the most recent Census Bureau statistics (2000), there are no minority or low income populations within the LSFO.
NI	Hazardous or Solid Wastes	Existing laws, regulations, standard lease stipulations, and contingency plans and emergency response resources are expected to adequately mitigate any potential hazardous or solid waste issues associated with the Proposed Action.
NP	Native American Religious Concerns	There are no known Native American Religious Concerns.
NP	Paleontological Resources	There are no known Paleontological Resources.
PI	Social and Economic Conditions	See Section 3.4.4
NI	Visual Resources	Area managed as Class III. Public surface lands are not part of this project.
Resource Uses		
NP	Access and Transportation	Public surface lands are not part of this project; therefore access and transportation are not affected.
NI	Fire Management	Public surface lands are not part of this project; therefore fire management is not affected.
NP	Forest Management	This resource is not present within the proposed project area.
NP	Livestock Operations	This resource is not present within the proposed project area.
NP	Prime and Unique Farmlands	No specially designated farmlands are present within the project area.
NP	Realty Authorizations, Land Tenure	There are no Realty Authorizations within the project area.
NP	Recreation	Public surface lands are not part of this project; therefore recreation is not affected.
Special Designations		

Determination[1]	Resource	Rationale for Determination
NP	Areas of Critical Environmental Concern	There are no ACECs within the project area.
NP	Lands with Wilderness Characteristics	There are no LWCs within the project area.
NP	Wilderness Study Areas	There are no WSAs within the project area.
NP	Wild and Scenic Rivers	There are no WSRs within the project area.

[1] NP = Not present in the area impacted by the Proposed Action or Alternatives. NI = Present, but not affected to a degree that detailed analysis is required. PI = Present with potential for impact analyzed in detail in the EA.

3.2 PHYSICAL RESOURCES

3.2.1 Air Quality and Climate

3.2.1.1 Affected Environment

The facility is located in the central portion of Routt County, Colorado (Section 23, Township 5 North, Range 86 West), approximately 21 miles Southeast of Hayden, Colorado (population approx. 1600), and south of State Highway 40 between the towns of Steamboat Springs to the east and Craig to the west. Topography in the project area and adjacent lands ranges in elevation from approximately 6,600 feet to 7,800 feet. The average elevation of the project area is approximately 7,040 feet. Terrain varies from rolling hills with agricultural fields and rangeland in the northwestern, central, and extreme southern extents of the project area to high ridges and steep slopes within the eastern and southwestern portions of the project area. The normal temperatures (min. and max.) for the area range from 4.8 to 29.1 ˚F in January to 46.9 to 83.7 ˚F in July. The regional average annual precipitation amounts to approximately 19.01 inches, which according to historical records shows the lower elevations receiving relatively higher precipitation amounts in summer, while the higher elevations receive relatively higher amounts of precipitation in winter. Average annual wind resultants are generally from the east south east at speeds of approximately 3.6 to 8.8 mph for a majority of the time.

Air quality in the region is affected by multiple activities currently conducted within the area, which generally consists of smaller communities adjacent to the State Highway (SH) 40 corridor. Therefore it is reasonable to conclude that indirect and cumulative effects on air quality in the area would be influenced in the near field by sources of emissions within 50km of the project site. Activities occurring within the area that affect air quality include stationary source facilities such as coal mines and subsequent coal mining operations (e.g., loading), concrete mix plants, gravel mines/pits, lime storage facilities, coal fired electrical generating plants, natural gas dehydration facilities, landfills, etc. Portable source examples include facilities such as gravel crushers, associated processing equipment, and asphalt plants. Mobile sources of emissions within the region would include highway or on-road vehicles, off-road vehicles such as construction related equipment (dozers, loaders, backhoes, etc…), and recreational vehicles (snowmobiles, ATVs, and dirt bikes). Smoke from grass and forest fires represent area source emissions that can impact air quality.

Implementation of the Proposed Action Alternative would result in emissions of criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHGs). Fugitive particulate matter would be emitted when haul trucks and other vehicles associated with the mining activities travel on existing dirt roads or overland access routes to load-out locations. Emissions of particulate matter would be generated from processing equipment, material handling transfer points (including rail load-out locations), storage piles, and mine ventilation shafts. Air quality would also be impacted by fuel combustion sources, such as the engine exhaust emissions from locomotives, mobile material handling equipment, personnel transport equipment, and any stationary fuel combustion sources.

3.2.1.1.1 Regulatory Framework

The Clean Air Act (CAA), which was last amended in 1990, requires the Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) (40 CFR part 50) for criteria pollutants. Criteria pollutants are air contaminants that are commonly emitted from the majority of emissions sources and include carbon monoxide (CO), lead (Pb), sulfur dioxide (SO_2), particulate matter smaller than 10 & 2.5 microns (PM_{10} & $PM_{2.5}$), ozone (O_3), and nitrogen dioxide (NO_2).

The CAA established 2 types of NAAQS:

Primary standards: – Primary standards set limits in order to protect public health, including the health of "sensitive" populations (such as asthmatics, children, and the elderly).

Secondary standards: – Secondary standards set limits in order to protect public welfare, including protection against decreased visibility, and damage to animals, crops, vegetation, and buildings.

The EPA regularly reviews the NAAQS (every five years) to ensure that the latest science on health effects, risk assessment, and observable data such as incidence rates are evaluated in order to re-propose any NAAQS to a lower limit if the data supports the finding.

The Colorado Air Pollution Control Commission, by means of an approved State Implementation Plan (SIP) and/or delegation by EPA, can established state ambient air quality standards for any criteria pollutant that are at least as stringent as, or more so, than the federal standards. Ambient air quality standards must not be exceeded in areas where the general public has access. Table 2 lists the federal and state ambient air quality standards.

Table 2, Ambient Air Quality Standards (EPA 2011)

Pollutant [final rule cite]		Primary/ Secondary	Averaging Time	Level	Form
Carbon Monoxide [76 FR 54294, Aug 31, 2011]		primary	8-hour	9 ppm	Not to be exceeded more than once per year
			1-hour	35 ppm	
Lead [73 FR 66964, Nov 12, 2008]		primary and secondary	Rolling 3 month average	0.15 $\mu g/m^3$	Not to be exceeded
Nitrogen Dioxide [75 FR 6474, Feb 9, 2010] [61 FR 52852, Oct 8, 1996]		primary	1-hour	100 ppb	98th percentile, averaged over 3 years
		primary and secondary	Annual	53 ppb	Annual Mean
Ozone [73 FR 16436, Mar 27, 2008]		primary and secondary	8-hour	0.075 ppm	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years
Particle Pollution [71 FR 61144, Oct 17, 2006]	$PM_{2.5}$	primary and secondary	Annual	15 $\mu g/m^3$	annual mean, averaged over 3 years
			24-hour	35 $\mu g/m^3$	98th percentile, averaged over 3 years
	PM_{10}	primary and secondary	24-hour	150 $\mu g/m^3$	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide [75 FR 35520, Jun 22, 2010] [38 FR 25678, Sept 14, 1973]		primary	1-hour	75 ppb	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		primary	Annual	0.03 ppm[1]	Arithmetic Average
		secondary	3-hour	0.5 ppm	Not to be exceeded more than once per year

[1] State of Colorado Primary Standard.
NOTE: Air quality in the Routt County currently meets all NAAQS & CAAQS.

3.2.1.1.2 Emissions, Source Classifications and Regulatory Authority

Emissions sources are generally regulated according to their type and classification. Essentially all emissions sources fall into two broad categories, stationary and mobile.

Stationary sources are generally non-moving, fixed-site producers of pollution such as power plants, chemical plants, oil refineries, manufacturing facilities, and other industrial facilities. This source class can also cover certain types of portable sources (based on regulatory technicalities). Stationary facilities emit air pollutants via process vents or stacks (point sources) or by fugitive releases (emissions that do not pass through a process vent or stack). Stationary sources are also classified as major and minor. A major source is one that emits, or has the potential to emit, a regulated air pollutant in quantities above a defined threshold. Stationary sources that are not major are considered minor or area sources. Stationary sources that take federally enforceable limits on production, consumption rates, or emissions to avoid major source status are called synthetic minors. The Colorado Department of Public Health and Environment (CDPHE), Air Pollution Control Division (APCD) has authority under their approved SIP, or by EPA delegation, to regulate and issue Air Permits for stationary sources of pollution in Colorado.

Mobile sources include any air pollution that is emitted by motor vehicles, engines, and equipment that can be moved from one location to another (typically under their own power). Due to the large number of sources, which includes cars, trucks, buses, locomotives, construction equipment, lawn and garden equipment, aircraft, watercraft, motorcycles, etc…, and their ability to move from one location to another, mobile sources are regulated differently than stationary sources. In general EPA and other federal entities retain authority to set emissions standards for these sources depending on their type (on-road or off-road) and class (light duty, heavy duty, horse power rating, weight, fuel types, etc.). Mobile sources are not regulated by the state (an exception being California) unless they are covered under an applicable SIP specific to a non-attainment or maintenance area requirement.

3.2.1.1.3 Criteria Pollutants

All the criteria pollutants shown in Table 2 above can be directly emitted by various stationary and mobile sources, with the exception of ground level ozone and secondary $PM_{2.5}$ (also known as condensable particulate matter).

Ozone is chemically formed in the atmosphere via complex reactions of oxides of nitrogen (NO_X) and volatile organic compounds (VOCs) in the presence of sunlight and under certain meteorological conditions (NO_X and VOCs are Ozone precursors). In general, ozone concentrations in the lower atmosphere are highest during warmer months, when the incidence angle of the sun relative to the surface is optimal to support the reactions. In some parts of the western U.S., high winter-time ozone concentrations have been monitored, and these events have generally been linked to areas with high snow cover. It is hypothesized that adequate snow cover (depth) effectively reflects UV radiation striking the ground, essentially 'doubling' the effective path length and potential reaction rates of any ozone forming region in the atmosphere relative to the total available UV reaching the surface. Ozone formation and prediction is complex, non-linear, and generally results from a combination of significant quantities of VOCs and NO_X emissions from various sources within a region. Ozone formation may not occur within the resource area, and once formed it has the potential to be transported across long ranges. Therefore, it is typically not appropriate to assess the potential ozone impacts that a single project, where increases in precursor emissions will occur, can have on regional ozone formation and transport. However, the State assesses potential ozone impacts from its authorizing activities on a regional basis when an adequate amount of data is available and where such analysis has been deemed appropriate. For this reason (inappropriate scale of analysis), ozone will not be further addressed in this document beyond the related precursor discussions, and an appropriate qualitative analysis.

According to the EPA fine particulate matter ($PM_{2.5}$) is chiefly comprised of five mass components: organic carbon, elemental carbon (also known as soot or black carbon), ammonium sulfates, ammonium nitrates, and crustal materials (i.e., soil). Primary fine particulate emissions result from combustion processes (including fossil fuel combustion and biomass combustion that occurs in wild fires) and include organic and black carbon. A minority component of primary $PM_{2.5}$ is made up of crustal elements (i.e. fugitive dust, generally 5-15%). Condensable particulate matter, or secondary $PM_{2.5}$ particles, are primarily ammonium sulfate and ammonium nitrate formed in the atmosphere from gaseous emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X), reacting with ammonia (NH_3). The largest constituents of fine particulate are usually organic mass, ammonium nitrates, and ammonium sulfates. Secondary particulates do not result from emissions of fugitive dust (which is the largest emissions category from the Twentymile Coal Foidel Creek Mine), and thus will not be discussed further in this document.

3.2.1.1.4 Hazardous Air Pollutants

Toxic air pollutants, also known as hazardous air pollutants (HAPs), are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. The majority of HAPs originate from stationary sources (factories, refineries, power plants) and mobile sources (e.g., cars, trucks, buses), as well as indoor sources (building materials and cleaning solvents). No ambient air quality standards exist for HAPs; instead emissions of these pollutants are regulated by a variety of laws that target the specific source category and industrial sectors for stationary, mobile, and product use/formulations. The majority of HAPs emitted from the Foidel Creek mine's operations are the result of the on-road and non-road vehicle use. The largest component of the HAPs emissions from these sources are typically various benzene compounds, and the majority of them are emitted from spark ignition (gasoline fueled) combustion sources. This is simply due to the fact that benzene is present in larger % volumes in the fuel (typically 1.0% vs. 0.05% for diesel fuel).

3.2.1.1.5 Green House Gases

Gases that trap heat in the atmosphere are often called greenhouse gases, and include carbon dioxide (CO_2), water vapor, methane (CH_4), Nitrous Oxide (N_2O), and several fluorinated species of gases such as hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Carbon dioxide is emitted from the combustion of fossil fuels (oil, natural gas, and coal), solid waste, trees and wood products, and also as a result of other chemical reactions (e.g., manufacture of cement). Methane is emitted during the production and transport of coal, natural gas, and oil. Methane also results from livestock and other agricultural practices and by the decay of organics in both the natural environment and from wastes in municipal landfills. Nitrous oxide is emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste. Fluorinated gases are powerful greenhouse gases that are emitted from a variety of industrial processes and are often used as substitutes for ozone-depleting substances (i.e., Chlorofluorocarbons (CFCs), Hydrochlorofluorocarbons (HCFCs), and halons).

These gases all have various capacities to trap heat in the atmosphere, which are known as global warming potentials (GWPs). Carbon dioxide has a GWP of 1, and so for the purposes of analysis a GHG's GWP is generally standardized to a carbon dioxide equivalent (CO_2e), or the equivalent amount of CO_2 mass the GHG would represent.

As with the HAPs, ambient air quality standards do not exist for GHGs. In its Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, the EPA determined that GHGs are air pollutants subject to regulation under the CAA. The most recent rules promulgated by EPA to regulate GHG emissions and the industries responsible are the Mandatory Reporting Rule (74 FR 56260) and the Tailoring Rule (70 FR 31514). Under the Mandatory Reporting Rule, Underground Coal Mines subject to the rule are required to report GHG emissions in accordance with the requirements of Subpart FF. Under the provisions of the Tailoring Rule (step 2 – July 2011) a facility would be subject to PSD permitting if it has the potential to emit GHGs in excess of 100,000 tpy of CO_2e equivalent and 100/250 tpy of GHGs on a mass basis. For existing facilities this review would take place during any subsequent modifications to the facility that would trigger a permit review (CDPHE's anticipated implementation strategy).

3.2.1.1.6 Air Quality and Prevention of Significant Deterioration

Air quality for any given area (any geographical area that defines the class boundary) is designated as either attainment, or nonattainment. Attainment areas are those areas where criteria pollutant concentrations in ambient air do not exceed the NAAQS levels as outline above. Areas or regions where criteria pollutant concentrations in ambient air exceed the NAAQS levels are designated as nonattainment for the NAAQS. Two additional subset categories of attainment exist for those areas where a formal designations have not been made, i.e. Attainment/Unclassifiable (generally rural, or natural areas), and for areas where previous violations of the NAAQS have been documented, but pollution concentrations no longer exceed NAAQS concentrations, i.e. Attainment/Maintenance areas. Routt County is designated as an attainment area for all NAAQS pollutants.

All geographical regions are assigned a priority Class (I, II, or III) which describes how much degradation to the existing air quality is allowed to occur within the area under the Prevention of Significant Deterioration (PSD) regulations. Class I areas are areas of special national or regional natural, scenic, recreational, or historic value, and essentially allow very little degradation in air quality, while Class II areas allow for reasonable industrial/economic expansion. There are currently no Class III areas defined in Colorado. The closest PSD Class I areas (which require the most stringent protection for air quality) are Mount Zirkel and the Flat Tops Wilderness Area, located approximately 30 miles to the Northeast and 18 miles South of the proposed modification area, respectively.

For an area that is in attainment for the NAAQS and CAAQS, the CAA provides specific criteria for stationary sources to allow for economic growth under the PSD regulations (40 CFR 52.21 or 40 CFR 51.166 for SIP approved rules). Major PSD sources (or major modifications to existing PSD sources) are required to provide an analysis to ensure their net emissions will not cause or contribute to a violation of any applicable NAAQS or PSD increment. In addition, the analysis required for permitting must include impacts to surface waters, soils, vegetation, and visibility (also known as air quality related values (AQRVs)) caused by increases in emissions, and from any associated growth (or growth in industrial, commercial, and residential sectors that will occur in the area as a direct result of the source). Where a PSD source is located near a Class I airshed (within 50km) the AQRVs thresholds set by the applicable Class I controlling agency (Federal Land Manager) must be assessed to determine if an adverse impact on the area is likely to occur. According to the most recent valid permit issued by CDPHE, the Foidel Creek Mine is not a major PSD source for criteria pollutants.

Given the above and the fact that the BLM is not the regulatory authority authorizing emissions and enforcing applicable permit conditions for the mine's operations, and the proposed action does not authorize or anticipate an increase in emissions from the Foidel Creek Mine, the BLM will not be providing any additional analysis for any potential Class I area direct impacts for the proposed action since they are not expected to occur.

3.2.1.2 Environmental Consequences, Proposed Action

3.2.1.2.1 Emissions Inventory

The proposed action alternative will produce direct and indirect emissions of the above identified pollutants. As stated in the proposed alternative action, and no action alternative, emissions rates or intensities would not increase under either alternative and therefore the emissions inventory can reasonably be expected to be the same for each alternative based on the fact that authorized production rates would not increase under either scenario.

Direct Emissions

With the exception of particulate matter, all of the directly emitted criteria pollutants originating from the mine's operations are from fuel combustion sources, such as mobile mining equipment, haul trucks, and stationary sources (emergency generators, light poles, heaters, etc.). HAPs and GHGs are also emitted from fuel combustion sources, albeit in de minimis amounts. Coal Mine Methane (CMM) will also be emitted by the ventilation air handling system required by MSHA to reduce the combustion / explosion potential of the mine's underground atmosphere (also known as Ventilation Air Methane or VAM). Twentymile Coal, LLC does not drill gob vent boreholes (GVB) for its operations at the Foidel Creek Mine to vent methane due to the area's naturally low occurring presence of the gas in the coal formation, overburden, and surrounding strata, and therefore the company does not plan, project, or possess MSHA permits / approved plans requiring GVB drilling at this time. VAM will be the only source of CMM emissions at the Foidel Creek Mine. Methane emissions from this activity would require reporting to EPA under the previously mentioned Mandatory Reporting Rules if reporting thresholds are exceeded.

Although methane is not a regulated volatile organic compound, recent analyses of CMM gas from other mines in Colorado, including the West Elk and Elk Creek mines in the North Fork Valley (Delta and Gunnison Counties), indicate that regulated volatile organic compounds make up a percentage of the CMM constituents, and these gases would be released as a result of CMM venting. Peabody Energy has yet to perform or initiate a thorough screening assessment of its operations to determine the mine's status for VOC emissions under the clean air act. Although the BLM is not the regulatory agency for determining major source status for stationary sources of emissions (i.e. CDPHE), it is likely that a screening / CMM sampling analysis would need to be initiated for a sufficient period of time to determine if there is a reasonable correlation between the gases' methane and VOC percentages. This would allow the mine and/or CDPHE to perform a back calculation of the mine's known CMM releases from its required MSHA sampling data and determine a reasonable total for any VOCs released. If, through sampling, it is shown that a reasonable correlation does not exist (i.e. highly variable percentages), then more detailed and prolonged sampling and gas analysis would probably be required to make a determination of regulatory applicability. Given the low permitting thresholds for VOCs in Colorado, it is likely the mine would be subject to at least minor source permitting or APEN submissions. To reiterate, CDPHE, not the BLM, will determine an appropriate methodology and or requirements to determine regulatory applicability for these sources of emissions in Colorado. It is the BLM's understanding through personal communication with CDPHE staff that discussions within APCD are ongoing about providing resolution for this matter on a state-wide basis.

Stationary sources (including any area and fugitive emissions) at the Foidel Creek Mine are regulated by CDPHE where applicable and are authorized by APCD permit number 93RO1204. The permit provides limitations and requirements to limit potential emissions from the site to below major source thresholds for certain criteria pollutants. The Foidel Creek Mine is currently classified as a synthetic minor source for all criteria pollutants and would therefore not be subject to the PSD rule requirements for permitting of those pollutants at this time. When pollutants are not explicitly addressed in an APCD permit it is due to the fact that those emissions are below CDPHE's permitting thresholds, or in the case of GHGs, are not part of the minor source permitting program. The Foidel Creek Mine last had its air permit revised and issued by APCD on Jan. 12, 2012. It is unclear if CDPHE evaluated the status of the mine for major source determination for GHG's. As previously stated, Twentymile Coal, LLC does not anticipate modifying their permit to accommodate any additional production they would realize from the availability of additional coal reserves within the proposed LBA area. Stationary sources of direct emissions at the Foidel Creek Mine include the following:

- Material Handling Conveyors
- Mine Ventilation Shafts
- Internal Combustion Engines
- Fuel Storage Tanks
- Material Processing Screens (93RO1204)
- Material Processing Crushers (93RO1204)
- Surface Operations (fugitive PM)
- Misc. Facility Heating Equipment

HAP emissions from stationary sources are considered de minimis. For the purposes of disclosing impacts from the alternatives proposed, insufficient data and analysis exists to determine if any portion of the ventilation air emissions would be considered a hazardous air pollutant. Of the sources identified above, only the fuel tanks, internal combustion engine, and miscellaneous heating equipment would generate HAP emissions. Because of the limited use or the exempt status of the identified units, expected cumulative HAP emissions from these sources would be on the order of pounds per year, and therefore will not be analyzed any further in this document.

Mobile sources at the facility include underground mining equipment, listed under source classification code (SCC) 2270009010, aboveground construction equipment identified under SCC 2270002000, as well as light duty gasoline trucks and light and heavy duty diesel trucks. The underground mining mobile sources are specialized, industry specific equipment designed to function in the unique environment of an underground mine, while the aboveground sources would be heavy construction equipment used for material handling and stockpile management.
To provide acceptable emissions estimates and to fully disclose expected direct emissions from the facility's expected underground mobile sources, BLM staff utilized EPA's Nonroad model (2008a) to generate SCC specific emissions factors (grams per horsepower-hour) for Routt County based equipment inventories (underground mining) for the year 2005. The year 2005 inventory was chosen to match the inventory that was provided for the surface sources from the Sage Creek mine modeling report sent to APCD, which also included the Foidel Creek Mine equipment emissions inventory. To estimate emissions from the sources, BLM staff had to determine a reasonable thermal efficiency (TE) for the diesel equipment in order to determine the total horsepower-hours the mine's annual fuel use would provide to the equipment. This was necessary because the annual fuel use was the only fleet specific variable the BLM had to estimate emissions. Appendix A contains a more thorough description of the basis of the calculations, example TE calculations, total horsepower-hours calculations, emissions factor selection, emissions calculations, and any applicable references used to support the mobile source emissions data in Table 3 below.

Peabody Energy also uses light duty gasoline and diesel trucks (LDGT & LDDT) to ferry personnel, equipment, and supplies around the mine and also between the Sage Creek Mine (idled in September 2012) to conduct daily business. Peabody provided the annual fuel use (diesel and gasoline) for these sources, however BLM staff could not delineate the minor amount of diesel that would be consumed by the LDDT from the Heavy equipment use since no information was available to describe the LDDT fleet characteristics or annual vehicle miles travelled, and therefore no emissions estimates from these sources are provided (analysis assumes all the diesel fuel is consumed in heavy equipment).

Table 3 Direct Criteria and GHG Emissions from Stationary and Mobile Sources (2011 – Tons)

Sources Types	PM_{10}	$PM_{2.5}$	VOC	CO	NO_X	SO_2	CO_2	CH_4	N_2O
Aggregates / Mine Vents (93RO1204)	55.07	17.88	NA	NA	NA	NA	NA	NA	NA
Fugitives (93RO1204)	105.27	14.95	NA	NA	NA	NA	NA	NA	NA
Fuel Storage Tanks (XA)	NA	NA	3.99[1]	NA	NA	NA	NA	NA	NA
Emergency Generator (TBD)	0.01	0.01	0.01	0.14	0.13	0.00	19.43	0.00	ND
Methane Sources (VAM)	NA	NA	ND	NA	NA	NA	26,391	1,256.71[2]	NA
Mics. Heating Equipment	0.17	0.42	0.67	6.28	10.89	0.42	10,468	0.17	0.08
Underground & Surface Mining Equipment	12.98	12.59	21.17	86.13	95.88	0.07	7204.02	0.32	0.18
Pick-ups (LDGT)	0.05	0.05	0.08	1.13	0.12	0.04	166.56	ND	ND
Total Direct Emissions (tons)	**173.55**	**45.90**	**25.92**	**93.68**	**107.02**	**0.53**	**44,249.01**	**1,257.20**	**0.26**

1 Emissions based on APEN exemption (XA) threshold in attainment area (< 2.0 tpy) x 2 tanks.

2 The CO_2e of the methane gas is approximately 26,391tons.

Indirect Emissions

Electrical energy consumed at the site can reasonably be expected to produce emissions from the supplying source, unless that source is some form of renewable energy. It is possible to provide rough estimates of emissions resulting from mine electricity consumption if the annual energy consumption data is known. Reasonable emissions estimates can be made for some pollutants (NO_X, SO_2, CO_2, N_2O, & CH_4) by making use of EPA's Emissions & Generation Resource Integrated Database (eGRID). The eGRID tool is a comprehensive inventory of environmental attributes of electric power systems and is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government, including the following agencies: EPA, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Emissions data collected by EPA is integrated with generation data from EIA to produce useful values like pounds of emissions per megawatt-hour (lb. /MWh), which allows direct comparison of the environmental attributes of electricity generation by state, U.S. total, company, and by three different sets of electric grid boundaries. Table 4 provides an estimate of indirect emissions for the mine's electrical consumption data for 2011. The most recent data available online (2005) suggests Colorado imports only 1-3% of its total electricity demand on an annual basis. For the practical purposes of this EA, BLM considers Colorado to be neither a net energy exporter, nor importer, and therefore all indirect emissions estimates from mine electricity consumption are based on Colorado source data.

Locomotive emissions from hauling the mined and processed coal are currently occurring in the proposed action area and would continue under the Proposed Action Alternative. It is estimated that 70% of all railroad traffic in the U.S. is dedicated to the transport of coal. Although this statistic may be appropriately applied to certain metropolitan statistical areas, it may not reflect actual rail traffic composition for Routt County. BLM could not locate any data to suggest otherwise, but to be conservative in our analysis an assumption was made that all rail emissions in Routt County are from coal hauling, and further, that all rail emissions are attributed to the Foidel Creek Mine's operations (although the Trapper Mine in Craig, Colorado, is also likely responsible for some of the coal hauling rail traffic). It is highly likely that emissions from this source class have been decreasing, and will continue to do so in the future, due to the implementation of new emissions standards for new and reconstructed locomotives (2000 and 2008). EPA estimates that the average useful life for these engines is 750k miles or 10 years, whichever occurs first, meaning that on average an engine is replaced or reconstructed every ten years and will have to comply with the most stringent emissions requirement applicable to the engine at that time.

Combustion of the mined and processed coal will produce all of the emissions outlined in section 2. According to U.S. EPA figures contained in the Draft US GHG Inventory Report (2012), nearly 95% percent of all coal consumed in the U.S. during 2010 was used in the generation of electric power. Because of this, it can reasonably be assumed that the coal from the Foidel Creek Mine will be shipped to a coal-fired power plant. It would be possible to provide an estimate of Criteria, HAP, and GHG emissions associated with the burning of the mined coal at a specific facility; however, the types and location of the facilities the coal might be processed and consumed in is speculative and not foreseeable. The contractual agreements between the coal fired power plant and the coal supply company are outside the scope of this analysis, and the BLM does not determine at which facilities the coal would be consumed. Additionally, different emissions control devices, firing practices, and the age/overall efficiency of any specific power plant could greatly affect the amount of Criteria, HAP and GHG emissions that are released into the atmosphere. For example, a power plant that is equipped with selective catalytic reduction or practices CO_2 capture would ultimately release much smaller quantities of NO_X and CO_2 than a power plant lacking such controls.

Even though the BLM cannot reasonably say where all of the coal produced by the mine will be consumed, it is still possible to do emissions calculations to estimate certain criteria and GHG emissions from the combustion of the coal. Just as the mine's electrical consumption data can be utilized in concert with the eGRID data to produce emissions estimates, the same can be done for coal combustion for any production volume if the energy content of the coal is known or can be reasonably estimated. To produce these estimates BLM staff used eGRID data for state, regional, and national levels to produce a worst case scenario from the emissions profiles. The three scenarios were produced based on the fact that BLM cannot reasonably predict where the coal might be consumed. The current online eGRID data is several years old now, and it is expected that newer emissions rules for visibility SIPs such as Best Available Retrofit Technology (BART) will lower the overall coal fired power plant emissions over time, and therefore the estimates provided in table 4 below are considered conservative.

Table 4. Indirect Criteria and GHG Emissions (tons)

Source[1,4]	PM_{10}	$PM_{2.5}$	NMOG	CO	NO_X	SO_2	CO_2	CH_4	N_2O
Electricity[2] Consumption	ND	ND	ND	ND	183.9	159.5	120,240	1.48	1.84
Rail Hauling[3]	8.19	7.53	12.18	35.09	237.18	2.48	ND	ND	ND
Coal Combustion (State -CO)	ND	ND	ND	ND	36,678	32,713	21,905,398	ND	ND
Coal Combustion (Regional – RMPA)	ND	ND	ND	ND	30,565	25,222	20,463,705	ND	ND
Coal Combustion (National)	ND	ND	ND	ND	28,385	77,076	19,481,558	ND	ND
Total Indirect Emissions (tons)[5]	**8.19**	**7.53**	**12.18**	**35.09**	**37,099**	**77,238**	**22,025,638**	**1.48**	**1.84**

1 ND = No Data

2 Electricity consumptions estimates made from 2008 eGrid data for producers within Colorado, & 2011 electrical consumption data.

3 Emissions from 2008 EPA NEI Mobile – Locomotives Data for Routt County, CO. Assumes all emissions from Foidel Creek coal hauling.

4 Coal combustion emissions estimates made from 2008 eGRID data, based on Foidel Creek Coal BTU and 2011 production.

5 Total Indirect Emissions include the worst case (highest emissions) scenario for coal combustion out of the 3 presented.

Table 5. Routt County National Emissions Inventory Data (EPA 2008)

CO County Reported Emissions by Source **Routt**	PM_{10}	$PM_{2.5}$	VOC	CO	NO_X	SO_2	CO_2	CH_4	N_2O	NH_3	HAPs
Emissions Sector Summary											
Agriculture	240.52	48.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biogenics	0.00	0.00	0.00	2,552.47	150.26	0.00	0.00	0.00	0.00	0.00	1,379.41
Commercial Cooking	5.89	5.89	0.83	2.18	0.00	0.00	0.00	0.00	0.00	0.00	0.36
Dust	2,636.29	409.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fires	215.37	182.52	492.85	2,084.56	32.15	16.80	26,696.42	102.81	0.00	34.29	51.20
Fuel Comb	299.73	155.14	192.01	1,237.73	7,083.66	2,556.62	0.00	0.00	0.00	35.26	34.54
Gas Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.86
Industrial Processes	537.56	143.14	72.15	16.40	5.70	0.00	0.00	0.00	0.00	0.00	1.17
Miscellaneous Non-Industrial NEC	0.00	0.00	17.87	0.00	0.05	0.01	0.00	0.00	0.00	0.00	1.55
Mobile	91.30	79.19	749.27	6,597.66	1,418.38	33.65	223,953.77	12.90	2.06	14.75	202.71
Solvent	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.97
Waste Disposal	17.28	9.94	2.30	0.17	0.21	0.13	0.00	0.00	0.00	0.09	4.12
Total County Emissions (tons) =	**4,043.94**	**1,033.87**	**1,527.29**	**12,491.19**	**8,690.41**	**2,607.20**	**250,650.18**	**115.71**	**2.06**	**84.38**	**1,697.89**

3.2.1.2.2 Air Quality Impacts

The region surrounding the proposed action alternative area (APCD-Mountain Counties) is currently designated as attainment for all criteria pollutants. The attainment status for pollutants in the project area is determined by monitoring levels of criteria pollutants for which National Ambient Air Quality Standards (NAAQS) and Colorado Ambient Air Quality Standards (CAAQS) apply. The attainment designation means that no violations of any ambient air quality standard have been documented in the area. The area around the proposed alternative action area is also identified as Class II, which allows for reasonable economic growth. The Proposed Action analyzed in this EA does not address any increase in production above currently authorized levels, and would not constitute adding additional production to previously authorized limits. Further, the action does not represent an increase in mining intensity within the region due to the fact that as the Sage Creek Mine (also owned by Peabody Energy) ramps up production, the Foidel Creek Mine's production will be decreasing and will eventually cease extraction operations, which should result in stable production yields across the contemporaneous timeframes.

Air Monitoring

The Mountain Counties are generally those located on or near the Continental Divide. They consist of mostly small towns located in tight mountain valleys. The primary monitoring concern is particulate pollution from wood burning and road sanding. Area communities range from Steamboat Springs in the north to Breckenridge near the I-70 corridor, as well as Aspen and Crested Butte in the central mountains, and Pagosa Springs in the south. Currently, there are six particulate (PM_{10}) and one gaseous (O_3) monitoring sites operated by the APCD in the Mountain Counties region.

Grand Junction (APCD-Western Counties) is the only large city in the area, and the only location that monitors for CO and air toxics in either monitoring region. In 2008, Rifle, Palisade, and Cortez began monitoring for ozone. The other Western County locations only monitor for particulates. They are located in Delta, Durango, Parachute, and Telluride. Currently, there are four gaseous pollutant monitors and 11 particulate monitors in the Western Counties area. There are one CO, three O_3, eight PM_{10}, and three $PM_{2.5}$ monitoring sites.

PM_{10} data trends are available back to 1987 where monitors existed. In 2004 there were 20 $PM_{2.5}$ monitoring sites in Colorado. Thirteen of the 20 sites were selected based on the population of the metropolitan statistical areas and included Denver, Grand Junction, Steamboat Springs, Colorado Springs, Greeley, Fort Collins, Platteville, Boulder, Longmont, and Elbert County. This is a federal selection criterion that was developed to protect the public health in the highest population centers. In addition, there were seven special-purpose monitoring (SPM) sites. These sites were selected due to historically elevated concentrations of PM_{10} or because citizens or local governments had concerns of possible high $PM_{2.5}$ concentrations in their communities. All SPM sites were removed as of December 31, 2006 due to the low concentrations of $PM_{2.5}$ measured and a lack of funding.

Because the Foidel Mine is primarily a source of PM_{10} emissions, only the recent monitoring data for particulate matter is shown below. More so than other pollutants, PM_{10} is a localized pollutant where concentrations vary considerably. Thus, local averages and maximum concentrations of PM_{10} are more meaningful than averages covering large regions or the entire state. The regional monitoring data for ozone, $PM_{2.5}$, and carbon monoxide suggests the air quality at the monitored locations is attaining the national standards. Since the mine's operations are not expected to contribute significantly to these pollutant measurements at monitored locations, the data was not included in the values table below. The data below is presented for qualitative purposes only.

Table 6. Localized Monitoring Data (2010)

County	Location	PM$_{10}$			PM$_{2.5}$	
		Annual[2]	24 Hour (Max)	3 Yr. Ave. Ex.	Annual	24 Hour
Pitkin	Aspen - Library 120 Mill St.	15.6	70	0	NA	NA
Routt	Steamboat Springs - 136 6th St.	21.7	99	0	NA	NA
Garfield	Rifle - Henry Building 144 E. 3	25.5	59	0	< 3 yrs. Data	< 3 yrs. Data
	Parachute - Elem. School 100 E. 2	22.5	125	0	NA	NA
Mesa	Grand Junction - Pitkin 645¼ Pitkin Ave.	26.8	171	1	NA	NA
	Grand Junction - Powell 650 South Ave.	22.9	155	0	9.3	34.5
	Clifton - Hwy. 141 & D Rd.	23	189	3	NA	NA

1 Source: Colorado Air Quality Data Report 2010, available at http://www.colorado.gov/airquality/tech.aspx

2 Annual standard rescinded

Potential Impacts Analysis for Criteria Pollutants

A detailed air quality assessment, including modeling, of the mine was recently conducted to support APCD permitting of the Foidel Creek Mine at currently authorized production rates. The current APCD permit issued by the State authorizes up to 13.3 million tons of Run of the Mine (ROM) coal to be produced and processed annually. ROM coal includes any produced waste aggregates separated from the coal product that is sold from the mine.

A near field dispersion model (AERMOD), and a subsequent analysis conducted by CDPHE, was accomplished for the Foidel Creek Mine in May, 2010 and August, 2010, respectively. The modeling protocol was approved by CDPHE prior to running the model and simulated multiple operating scenarios and included a cumulative impact assessment by aggregating nearby facilities including: The Sage Creek Coal Mine, Hayden Power Plant, Connell Pit, Routt County Landfill, Milner Landfill, and Mesa Gravel Pit. The modeled pollutants included stationary and fugitive sources of PM_{10} and $PM_{2.5}$, as these are the primary pollutants of concern emitted from aggregate handling and mining operations, as well as CO and SO_2. The model did not predict any significant impact level exceedances to ambient air quality resulting from the Foidel Creek Mine's operations, and subsequently APCD issued the initial approval permit for the mine.

As related to railway emissions, in March 2008, EPA finalized a three part program that will dramatically reduce emissions from diesel locomotives of all types -- line-haul, switch, and passenger rail. The rule will cut PM emissions from these engines by as much as 90 percent and NO_X emissions by as much as 80 percent when fully implemented. The rule sets new emission standards for existing locomotives when they are remanufactured--to take effect as soon as certified systems are available (as early as 2008). The rule also sets Tier 3 emission standards for newly-built locomotives, provisions for clean switch locomotives, and idle reduction requirements for new and remanufactured locomotives.

Finally, the rule establishes long-term, Tier 4, standards for newly-built engines based on the application of high-efficiency catalytic after treatment technology, beginning in 2015. Therefore it is reasonable to conclude that rail emission in Routt County going forward should continue to substantially decrease in the near future, and ultimately provide a benefit to the surrounding communities and environment. Although the mine will employ LDGT and LDDT vehicles to conduct daily operations these sources of emissions are insignificant compared to the heavy equipment sources. Further, their use should only increase slightly over the current intensity levels due to the Sage Creek Mine construction initiatives. It is likely their continued use and any associated increase will have a negligible effect on area air quality. With respect to all mobile sources at the site, emissions from these sources are not expected to impact regional air quality due to the fact that they are not significant in the context of the regional county emissions inventory and the fleet should have decreasing emissions as a whole in the future as changes are made to upgrade to newer equipment.

With respect to potential ozone formation, the county level analysis of the emissions inventory suggests the region is potentially NO_X limited. Therefore, to effectively limit any potential for ozone formation due to area emissions, control methods should focus on reducing NO_X emissions. By continuing to limit the minor reaction species, ozone formation potential from area emissions should remain small. The reader should be advised that only full scale photochemical grid modeling (which is beyond the scope of this EA) can reasonably predict the limiting reactant. BLM provides the above assertion based on reasonably available literature analyzing potential ozone formation in rural areas during the typical ozone season (i.e. summer). The Foidel Creek Mine sources (including all of the diesel fired mobile sources) and associated processing equipment are not significant sources of VOC emissions (see earlier discussion on CMM VOC data limitations), the photochemical reactivity potential of methane in the troposphere is considered negligible (40 CFR51.100 (s)), and therefore the mine's operations are not expected to contribute significantly to any regional ozone formation from its VOC emissions. The mine does emit a significant amount of NO_X on an annual basis, however the amount is not regionally significant compared to county emissions. Given that the area is currently attaining the ozone standard, and the mine is not anticipating changes in operations that would affect its current emissions volumes, impacts to current regional air quality are not expected.

Potential Impacts Analysis for Greenhouse Gas Pollutants

According to the U.S. Global Change Research Program (2009), global warming is unequivocal, and the global warming that has occurred over the past 50 years is primarily human-caused. Standardized protocols designed to measure factors that may contribute to climate change, and to quantify climatic impacts, are presently unavailable. As a consequence, impact assessment of specific impacts related to anthropogenic activities on global climate change cannot be accurately estimated. Moreover, specific levels of significance have not yet been established by regulatory agencies. Therefore, climate change analysis for the purpose of this environmental assessment within this air quality section is limited to accounting for GHG emissions changes that would contribute incrementally to climate change. Qualitative and quantitative evaluations of potential contributing factors are included where appropriate and practicable.

Methane emissions associated with the Foidel Creek Mine are anticipated to be very low when compared to other Colorado underground coal mines. The geology of the surrounding strata and composition of the coal itself produce very little emissions during room and pillar or continuous mining. This method of mining can cause a collapse of the overburden above the seam when the support pillars are stripped during retreat, but with the development of mains as described in the proposed action, stripping is not likely. As previously stated, no gob vent boreholes (GVB) will be drilled in advance of the mining to adequately provide for the health and safety of the miners, since emission of any methane liberated are being adequately managed via the main vent fans at the facility. Methane emissions estimates are provided in the direct emissions table above. The estimations are based on current emission levels at the mine (2011).

Approximately 10.5 percent of U.S. emissions of methane come from underground coal mining activities (EPA 2010). Based upon the ―Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2010 (Draft), February, 27, 2012, and the Final Colorado Greenhouse Gas Inventory and Reference Case Projections 1990-2020, October 2007, the total coal mining related methane emissions (CMM) in 2009 and 2005 were 70.10 tg (teragrams=one million metric tons), and 4.9tg on a CO_2e basis for the US and Colorado, respectively. Estimated total CMM emissions from the Proposed Action are approximately 26,391 short tons of CO_2 equivalent (at current or 2011 production rates) or 0.49% and 0.034% of the total calculated CO_2 equivalent emissions of CMM from Colorado and the U.S. Based on BLM's analysis, all of the GHG emissions from the Proposed Action are equivalent to 0.0641 tg on a CO_2e basis. This represents approximately 0.055% & 0.001% of all the gross GHG emissions (does not consider GHG sinks, i.e. "net emissions") from Colorado (2005 – 116.1tg) and the US (2009 – 6,643tg), respectively. If the calculated GHG emissions were compared with the global figures (2005 CO_2 equivalent emissions of 26,544tg, ―World Development Report 2010: Development and Climate Change, World Bank, 2010), the relative significance of the impact to the global scale of GHG emissions would be even further negligible.

Regardless of the accuracy of emission estimates, predicting the degree of impact any single emitter of GHGs may have on global climate change, or on the changes to biotic and abiotic systems that accompany climate change, is not possible at this time. As such, the controversy is to what extent GHG emissions resulting from continued mining may contribute to global climate change, as well as the accompanying changes to natural systems cannot be adequately quantified. The degree to which any observable changes can, or would be, attributable to the Proposed Action cannot be reasonably predicted at this time.

To provide some additional context, the EPA has recently modeled global climate change impacts from a model source emitting 20% more GHGs than a 1500MW coal-fired steam electric generating plant (approx. 14,132,586 metric tons per year of CO_2, 273.6 metric tons per year of nitrous oxide, and 136.8 metric tons per year of methane). It estimated a hypothetical maximum mean global temperature value increase resulting from such a project. The results ranged from 0.00022 and 0.00035 degrees Celsius occurring approximately 50 years after the facility begins operation. The modeled changes are extremely small, and any downsizing of these results from the global scale would produce greater uncertainly in the predictions. The EPA concluded that even assuming such an increase in temperature could be downscaled to a particular location, it "would be too small to physically measure or detect", see Letter from Robert J. Meyers, Principal Deputy Assistant Administrator, Office of Air and Radiation re: "Endangered Species Act and GHG Emitting Activities (Oct. 3, 2008). The project emissions are a fraction of the EPA's modeled source and are shorter in duration, and therefore reasonable to conclude that the project would have no measurable impact on the climate.

With respect to GHG emissions, the following climate change predictions were identified by the EPA for the Mountain West and Great Plains region (http://www.epa.gov/Region8/climatechange/pdf/ClimateChange101FINAL.pdf):

- The region will experience warmer temperatures with less snowfall.
- Temperatures are expected to increase more in winter than in summer, more at night than in the day, and more in the mountains than at lower elevations.
- Earlier snowmelt means that peak stream flow will be earlier, weeks before the peak needs of ranchers, farmers, recreationalist, and others. In late summer, rivers, lakes, and reservoirs will be drier.
- More frequent, more severe, and possibly longer-lasting droughts will occur.
- Crop and livestock production patterns could shift northward; less soil moisture due to increased evaporation may increase irrigation needs.
- Drier conditions will reduce the range and health of ponderosa and lodge pole pine forests, and increase the susceptibility to fire.
- Grasslands and rangelands could expand into previously forested areas.
- Ecosystems will be stressed and wildlife such as the mountain line, black bear, long-nose sucker, marten, and bald eagle could be further stressed.

No Action Alternative Under the No Action Alternative, the modification area would not be approved for mining. Criteria, HAP, and GHG emission associated with the proposed mining at Foidel Creek Mine modification area would not occur.

3.2.1.3 Mitigation

Criteria Pollutant Emissions

Mitigation measures and emissions controls would be implemented to reduce particulate matter/fugitive dust emissions during construction and ongoing production activities. Fugitive emissions resulting from all vehicles traveling on non-paved surfaces during all project phases would be controlled utilizing water, chemical suppression, or a combination of the two by applying frequently or as needed to the non-paved road surfaces and in accordance with any permit condition or approved fugitive dust control plan required by APCD. Storage piles would be watered as necessary to limit wind erosion potential and reduce fugitive emissions. Most of the coal transfer points and processing activities taking place at the Foidel Creek Mine are either enclosed, employ moisture controls, or use technologies such as bag houses and wet scrubbers to control emissions in accordance with the authorizing air quality permit requirements.

It is assumed the facility would continue to comply with their APCD issued air emissions permit provisions, and any other regulatory requirements the facility is subject to, now or in the near future (GHG emissions reductions, methane capture, New Source Performance Standards, etc.).

Greenhouse Gas Emissions

With regard to production activities at the mine, methane liberation from the mine may be reduced through mine planning, sealing previously mined areas, and degasification efforts. Although no dedicated methane drainage system (i.e. GVB drainage wells) will be employed at the mine due to the inherently low levels of methane originating from the overburden and mine itself, VAM controls could still be considered by the mine in light of the future expansion of operations currently being considered by the mine owner for the adjacent Sage Creek Mine, which will utilize the Foidel Creek Mine's surface facilities and main vents for its operations.

3.2.1.4 Cumulative Effects

Reasonably Foreseeable Cumulative Actions

The following actions within the region are known or are reasonably foreseeable.

- Potential Oil and Gas Lease Sales and Development
- Future Modifications of Sage Creek Mine (Exploration and LBAs)
- Future Modifications of Sage Creek Mine (Longwall)
- Oil Shale Development

The leasing decision for the Foidel Creek Mine would not authorize mining operations. The EA evaluates the potential impacts of mining the LBA area, because mining is a logical consequence of issuing a lease for continued operation of the mine. The EA assesses the cumulative impact on the environment which results from the operation of the proposed mine when added to other past, present, and reasonably foreseeable future actions that would add to the anticipated impacts of the proposed action.

The site-specific impacts analyzed in this EA are based on the assumption that if the lease is issued mining would proceed at the currently authorized production rate of 13.3 million tons per year. Actual historic average annual production is 7.5 million tons. Extraction of the coal resource would proceed in accordance with all current permit conditions. In addition, it is also assumed the mined coal will be sold to coal users in response to forecasts of demand for this coal. Historically these users have been electric utilities in the United States, although there is potential for sales outside the U.S. This coal market is open and competitive, and users can buy from the most cost effective suppliers that meet their needs.

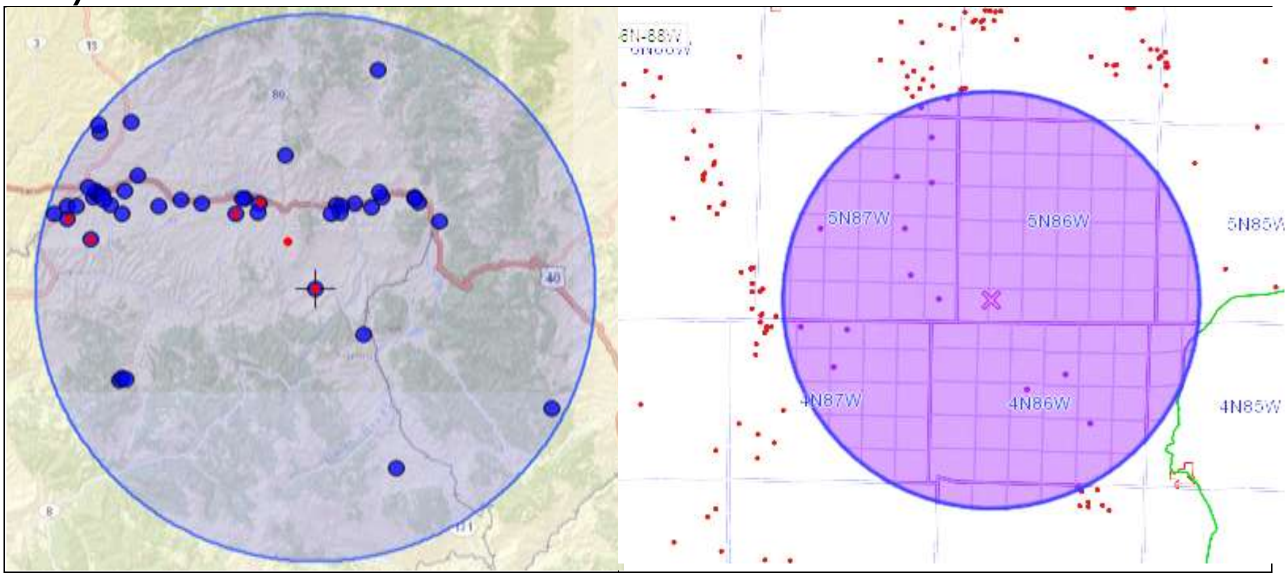
Area Emissions

The following emissions data is provided to the reader to provide a comprehensive picture of area emissions and to frame the analysis sections to follow.

Table 7. APCD APEN Sources of PM_{10} and $PM_{2.5}$

Distance (km)	AIRS ID	Facility Name	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
45.09	081-0018	TRI STATE GENERATION CRAIG	206.23	158.84
18.4	107-0001	PUBLIC SERVICE CO HAYDEN PLT	159.35	106.99
19.6	107-0013	HAYDEN GULCH TERMINAL INC	71.02	< 85th Percentile
40.9	081-0005	TRAPPER MINING INC	852.40	251.00
9.7	107-0009	SAGE CREEK COAL MINE	84.75	14.88
Total APEN Reported PM_{10} & $PM_{2.5}$ Emissions (within 50 km, all sources):			**1,755.19**	**642.34**

Figure 2. APCD PM_{10} & $PM_{2.5}$ Sources (50km buffer)[1] & COGCC Well locations (10km buffer)[2]



1 50km Buffer Map of PM_{10} sources generated from the following APCD website: http://www.colorado.gov/airquality/ss_map_wm.aspx, Foidel Creek Mine located at crosshair in the center of the buffer area. **Note:** Blue dots indicate all permitted or APEN sources in APCD Database, red highlights are for sources emitting PM10 > 85 percentile emissions for all APCD PM10 & PM2.5 sources.

2 10km Buffer Map of Well Locations generated from the following COGCC website: http://dnrwebcomapg.state.co.us/mg2010app/, Foidel Mine located at blue "X" in the center of the buffer area.

Table 8 COGCC Oil and Gas Well Production (Routt County)

Annual Production by County - 3 record(s) returned.			
Year	**Oil Production (barrels)**	**Gas Production (MCF)**	**Water Production (barrels)**
2009	68,012	69,598	11,837
2010	66,978	42,076	3,695
2011	64,270	37,191	24,51

The cumulative impacts to air quality in the Foidel Creek Mine area would result primarily from emissions of PM, NO_X, CO, CO_2, and CH_4 from the current and future mining of coal within the region. As previously stated, the long term plan for the Foidel Creek Mine is to gradually replace declines in production with those from the proposed Sage Creek Mine such that mining intensity for the region should not increase above currently authorized and evaluated levels.

With respect to oil and gas development, the BLM will address potential impacts from oil and gas development activities through the NEPA process when subsequent APD's are filed and operators will provide pertinent details of their proposals and operations such that BLM staff can provide a range of mitigation alternatives based on the project and cumulative impacts projections. At the pre-lease or lease stage any assumptions on development would be highly speculative and would need to account for economic factors such as supply, demand, and the current and projected price of natural gas, among various other considerations. However, when APDs are received BLM will accomplish the analysis and include any applicable cumulative impacts from the mine lease authorizations located within the region of influence of any well. A review of the COGCC database revealed a total of 30 producing, 10 located (not yet drilled), and 9 shut in wells for all of Routt County. Oil and Gas production for Routt County has been in decline in recent years, and the area is not expected to sustain much development in the future (according to the most recent draft of the Kremmling Field Office RMP), therefore cumulative impacts from whatever oil and gas activities do manifest in the future should be minor in relation to the primary pollutants of concern.

With respect to oil shale development, the technologies to extract this potential energy source are not yet proven, and therefore any future impacts (cumulatively or otherwise) associated with its development are too speculative to consider in this EA. However, the BLM is currently preparing a Programmatic EIS to address potential issues associated with oil shale development that may be beneficial to the reader when finalized. Project specific impacts from oil shale development will be evaluated when the economic viability of the resource is proven and reasonable alternatives for NEPA analysis can be developed.

Mining activities as well as other stationary sources of pollution related to air emissions are permitted by the Air Pollution Control Division of the CDPHE. The State imposes permitting limits and control measures in order to limit emissions of NAAQS pollutants. The State develops air quality attainment and maintenance plans in order to keep Colorado in compliance with the Federal NAAQS. Therefore, cumulative impacts are not anticipated to exceed NAAQS, or to push the region into non-attainment for any NAAQS, and should not result in any net change to baseline air quality. Further, the mine provided a detailed modeling analysis to support recent permit changes that was inclusive of several nearby emissions sources. The model results were reviewed and approved by CDPHE, and the permit for the mine was issued. With respect to mobile source emissions, mobile source continued use is not expected to increase over existing current service levels, and are therefore not expected to cumulatively impact regional air quality. If the last 30 plus years of the CAA is any guide, then emissions from these sources should continue to decline as fleets age and are replaced by better controlled units, such that even with record years of VMT, air quality in many areas of the county has vastly improved to the benefit of many local communities.

Ultimately, any near or far field impacts from criteria or HAP emissions associated with coal combustion emissions sources will, or have already, received analysis (and most likely permitting) from their respective regulatory agencies. Therefore, this action should not cause or contribute to the likeliness, frequency, or increasing severity of any detrimental impacts in areas at those respective sources.

Climate Change

Continued mining, operation of mine surface facilities, and associated vehicle traffic, would result in minor cumulative contributions to the release of GHGs into the atmosphere. The BLM estimated the amount of GHG emissions that could be attributed to coal production as a result of the proposed lease. The mining, processing, and shipping of coal from the Foidel Creek Mine would contribute to GHG emissions through carbon fuels used in mining (including fuel consumed by heavy equipment and stationary machinery), electricity used on site, methane released from mined coal, and rail transport of the coal. The use of the coal after it is mined has not been determined at this time; however, BLM assumed that all of the coal would be used as fuel in coal fired electric power generation facilities as part of the total U.S. use of coal for electric generation. This also results in the production of GHGs (see indirect emissions above). Policies regulating specific levels of significance have not yet been established for GHG emissions. Given the state of the science, it is not possible to associate specific actions with the specific global impacts such as potential climate effects. Since there are no tools

available to quantify incremental climate changes associated with these GHG emissions, the analysis cannot reach conclusions as to the extent or significance of the emissions on global climate.
The potential impacts of climate change represent the cumulative aggregation of all worldwide GHG emissions.

The Foidel Creek Mine lease modification would make an additional 40 acres of the Wadge coal seam available for mining. Coal production would be consistent with current regional production rates, and the anticipated release of GHGs from coal combustions would remain about the same as current rates. Climate change by nature is a cumulative process; however the predicted impacts were disclosed above and are assumed to be representative of global or cumulative GHG emissions accumulation.

3.2.2 Hydrology/Ground

See Section 3.2.8

3.2.3 Minerals/Solid

3.2.3.1 Affected Environment

Forty acres of Wadge coal seam coal would be leased. The Wadge seam averages 10 feet in thickness. Not all of the coal is mineable due to the increased steepness of the coal seam in the western side of the 40 acres. There is approximately 795,445 tons of mineable coal; approximately 644,000 tons are recoverable due to losses from mining methods (Combined Geologic Engineering Report and Maximum Economic Recovery Report for Twentymile Coal Lease Modification COC72980). The coal would be mined by underground methods. In the Little Snake Field Office, the coal planning area contains approximately 623,860 acres deemed acceptable for further consideration for leasing for either surface or underground development (Little Snake Record of Decision and Resource Management Plan (RMP)).

3.2.3.2 Environmental Consequences

Proposed Action

The Proposed Action would result in removal of the recoverable portions of the Wadge coal seam within the lease modification boundary by underground longwall mining techniques. Twentymile Coal anticipates mining 644,000 tons of coal over a 2 year period.
Indirect effects to solid mineral resources of the leased area would include controlled subsidence over the mined areas. In general, subsidence would be uniform over broad areas. Strata would subside as a block and retain their internal structure. Except for the removal of the coal bed, the overall nature of the solid mineral resources of the area would not change. The proposed action constitutes 0.006% of the 623,860 acres of the coal planning area.

No Action Alternative

The 644,000 tons of Wadge seam coal would not be leased, and consequently, not mined.

3.2.3.3 Mitigation

None

3.2.3.4 Cumulative Effects

The BLM does not authorize mining by issuing a lease for federal coal, but the impacts of mining the coal are considered in the cumulative impacts summary because it is a logical consequence of issuing a lease.

Past coal mining in the area includes the surface Energy Strip #1, the surface Yoast Mine, the surface Seneca I, Seneca II, and Seneca IIW Mines, the surface Johnson, the surface Commander Strip #1 and #3, the surface Fish, the surface Linholm, the underground Mt. Harris Mine and the surface Edna Mine.

Twentymile Coal has mined coal using underground methods at the Foidel Creek Mine since 1983. Approximately 100 million tons of coal has been mined at the Foidel Creek Mine[1]. There are approximately 5 more years of mining left at Foidel Creek Mine. Peabody has secured a long-term supply contract for 40 million tons of coal (Peabody Energy). Sage Creek Mine, approximately 5 miles to the north, will also mine the Wadge seam by underground methods under an existing permit. The 2006 Colorado Geological Survey estimated the remaining coal reserves in the Green River Coal Region to be 23,263 million tons. Mining the 644,000 tons would reduce the Green River Coal Region reserve by 0.00003%. Peabody Sage Creek Mining has a 6,197 acre coal exploration license that expires in 2014. The Sage Creek Mining exploration license is for 7 holes. This exploration license would have 0.14 acres of disturbance with approximately 21 days of exploration drilling activity. Sage Creek Mining was the successful bidder of a 400 acre coal lease (COC74219) to the north of this lease modification. Twentymile Coal has submitted a 200 acre lease by application located to the southeast of this lease modification. Reasonably foreseeable future actions would be:

- The continued mining at Twentymile Coal Foidel Creek Mine for approximately 5 more years.
- Sage Creek Mining was issued a 400 acre lease effective October 1, 2012. Mining began at Sage Creek in May of 2012, but is now temporarily halted until market conditions improve.
- On November 8, 2012, Peabody submitted an LBA for approximately 120 acres at the Twentymile Foidel Creek Mine.

3.2.4 Water Quality/Ground

3.2.4.1 Affected Environment

All of the impacts presented in this analysis are expected to occur as a result of the approved current mining operations, regardless of the decision to modify lease COC72980. No significant increased degradation of groundwater quality is anticipated as a result of the proposed leasing activity. Within the proposed lease modification area, the only bedrock units capable of regionally storing and transmitting water are the Trout Creek and the Twentymile Sandstones and the lenticular and interbedded sandstones of the three coal groups. Ground water occurrence, storage, and movement are associated with and controlled by the porosity and continuity of water bearing units, as well as structural gradients and faults. Ground water in the lease modification area is not suitable for domestic use (DRMS Cumulative Hydrologic Impact Assessment, Yampa River Basin, May 4, 2010). The one well within the lease modification area is owned by Twentymile Coal. The static water level depth is 120 ft. and the depth of the well is 700 ft. The depth to the Wadge seam is 1,600-1,700 ft. and is isolated from the bottom of the well by a 600 ft. confining marine shale layer.

[1] Department of Interior Office of Natural Resources Revenue Data Warehouse Portal (ONRR)

3.2.4.2 Environmental Consequences

Proposed Action

No water quality effects in the Twentymile Sandstone or the Trout Creek Sandstone would be anticipated during mining operations. The planned underground mining operations would result in localized and temporary drainage of ground water from the Wadge overburden (interbedded sandstones, siltstones and shales). The Twentymile Sandstone and Trout Creek Sandstone would not be affected since the thick, low permeability shales limit vertical water transmission between units. Following completion of mining, the mined-out area would be sealed and allowed to flood. Oxidation effects associated with contact between the ground water and exposed coal and overburden may result in changes in ground water quality and chemistry including increases in TDS and metals. These effects would be buffered by dilution by continued inflows and contact mixing with undisturbed ground water sources. These increased TDS concentrations would be limited to the overburden unit.

Any localized reduction in piezometric surfaces and/or changes in water quality and chemistry should not adversely affect water users since the well (Twentymile Coal) within the proposed lease area or adjacent areas do not intercept the Wadge overburden. Piezometric surface is defined as "The level at which the hydrostatic water pressure in an aquifer will stand if it is free to seek equilibrium with the atmosphere."

No Action Alternative

None. Not issuing the lease would have no impacts on ground water quality as there would be no mining as a logical consequence of issuing the lease.

3.2.4.3 Mitigative Measures

None.

3.2.4.4 Cumulative Effects

The Twentymile Coal Foidel Creek Mine has been in operation since 1983. Since that time groundwater quality has been monitored by monitoring wells. To date, there is no evidence that there is any significant connection between the mine workings and either the underlying Trout Creek Sandstone or the overlying Twentymile Sandstone. Twentymile Coal has an existing ground water monitoring system. It is used to document and assess any mining-related impacts to ground water. Cumulative effects from the Proposed Action could include dewatering of the Wadge overburden aquifer, the Twentymile Sandstone aquifer and the Trout Creek aquifer. Monitoring has shown that mining has had no impact at the Trout Creek Sandstone and water quality data from the mine inflow does not indicate any significant connection to either the overlying Twentymile Sandstone or the underlying Trout Creek Sandstone. Calculations predict that the Foidel Creek mining operation would cause a diminution of bedrock discharge from the Wadge overburden unit of about 11,000 gallons per day, equivalent to 0.02 cubic feet per second, for at least 360 years (DRMS Cumulative Hydrologic Impact Assessment, Yampa River Basin, May 4, 2010). This discharge is equivalent to 0.5 percent of the average low flow in Fish Creek which is the major creek receiving bedrock discharge. A diminution of this magnitude is not significant to flow conditions in Fish Creek. Periodic evaluation of the existing monitoring system would be conducted to adequately monitor impacts resulting from mining coal from the proposed lease tract.

3.3 HERITAGE RESOURCES AND HUMAN ENVIRONMENT

3.3.1 WASTES, HAZARDOUS OR SOLID

3.3.1.1 Affected Environment

Hazardous wastes produced by current mining activities at the Twentymile coal mine are handled in compliance with regulations promulgated under the Resource Conservation and Recovery Act, Federal Water Pollution Control Act (Clean Water Act), Safe Drinking Water Act, Toxic Substances Control Act, Mine Safety and Health Act, Department of Transportation, and the federal CAA. Mining operations must also comply with all state rules and regulations relating to hazardous material reporting, transportation, management, and disposal.

Disposal requirements for waste rock/ore derived from coal mining operations are based on whether the waste material is determined to be acid-forming and/or toxic-forming. If the material is determined to be non-acid-forming or non-toxic-forming, there are generally no restrictions on disposal. The material may be stockpiled within the permit area or disposed of per the Disposal of Excess Spoil, Coal Mine Waste Bank, or Coal Mine Waste Regulations (2 CCR 407-2.2.04.09 – 407-2.2.04.11). Acid-forming and toxic-forming waste material must be disposed of in accordance with 2 CCR 407-2.4.05.8 (Acid-forming and Toxic-forming Spoil), 2 CCR 407-2.4.10.1 (Coal Mine Waste Banks General Requirements), and 2 CCR 407-2.4.14.3.

Potential sources of hazardous or solid waste materials in the project area would include spilling, leaking, or dumping of hazardous substances, petroleum products, and/or solid waste associated with coal development or agricultural or livestock activities. No such hazardous materials are known to be present on the proposed Twentymile Coal 40 acre lease modification site at this time. If the lease modification area goes into production, petroleum products and solvents would be used underground as part of general operations. Use of these products would comply with all applicable state and federal regulations.

3.3.1.2 Environmental Consequences

Proposed Action

The 40 acre lease modification area is limited to underground mining. Impacts to the environment resulting from the release of hazardous or solid waste are not expected. The potential for impacts resulting from substance release would depend upon the responsible use of chemicals, and the immediate containment and adequate clean-up in the event of unintentional releases. The potential for exposure to hazardous or solid wastes would be low. Limited volumes of underground development waste would be generated from roof falls. To the extent practical, this material would be disposed of underground in mined-out areas. Coal refuse material (non-specification coal) and incombustible waste rock generated at Twentymile Coal is transported to the surface by conveyor, segregated and transported to Foidel Creek Mine’s approved refuse disposal area for permanent placement. Based on sampling and analysis of the geologic materials associated with Wadge seam in the Twentymile Coal permit area of the Foidel Creek Mine, the associated strata above and below the coal seam have little or no potential to generate acid- or toxic-forming refuse materials.

No Action Alternative
Under the No Action Alternative, there would be no impacts associated with hazardous or solid wastes.

3.3.1.3 Mitigation
If the lease is issued and mined, spill kits would be located onsite, which would be used in the case of an accidental spill in order to assist in rapid clean-up. Additionally, appropriate secondary containment would be utilized for all hazardous chemicals. Mining operations must also comply with all state rules and regulations relating to hazardous material reporting, transportation, management, and disposal.

3.3.1.4 Cumulative Effects:
In the past, the area has been mined by surface and underground methods. Present mining activities include Twentymile Coal Foidel Creek Mine and the adjacent Sage Creek Mine. The 40 acre lease modification would be mined using the same equipment that is currently operating at Twentymile Coal. The amount of petroleum products and solvents related to mining would remain at the current levels. Additional mining would produce corresponding quantities of hazardous and solid waste. These materials would continue to be managed and controlled under current regulations and best management practices. Cumulative impacts would be kept within state and federal guidelines and would be minor.

3.4.2 Social and Economic Conditions

3.4.2.1 Affected Environment

Proposed Action
The social and economic study area for the proposed lease action and associated mining includes Routt and Moffat counties and the communities of Steamboat Springs, Oak Creek, Hayden and Craig. These communities currently provide the workforce for the Foidel Creek Mine as well as providing mining services, retail, business and consumer services in the area. Steamboat Springs is the county seat of Routt County; Craig is the county seat of Moffat County.

Population
Table 6 presents basic population and demographic information for Moffat County and the state of Colorado. Although the lease and mine are in Routt County, well over half the workforce resides in Moffat County. For that reason, the demographics of Moffat County are presented here, as the greater influence would be on the residents of Moffat County.

Table 9. Population by Category, 2000 and 2009, Moffat County and the State of Colorado

Population	Moffat County	Colorado
2000		
2009		
% Change	+6%	+16.8%
Male (2009)	51.8%	50.4%
Female (2009)	48.2%	49.6%
Under 5 years	7.7%	7.3%
Under 18 years	26.5%	24.4%
65 years and over	9.4%	10.6%
% Minority (2008)	19.2%	29.3%

Population	Moffat County	Colorado
% Below poverty (2008)	9.5%	11.2%

Source: US Census Bureau, http://quickfacts.census.gov/qfd/states/08/08051.html

Moffat County comprises 4,742.25 square miles with 2.8 people per square mile and a total population of 13,980 people in 2009. Moffat County grew by almost 800 people between 2000 and 2009. According to the Sonoran Institute (2004), Moffat County grew slower than the state but faster than the nation between 1970 and 2000, with an annual average growth rate of 0.67%. The median age in Moffat County is 35 years old, with 26.5 % of the population being under the age of 18 and almost 9.5% being 65 years or older. Over 79.6% of the people age 25 and older in Moffat County have graduated from high school, and just over 12% have graduated from college (US Census Bureau 2001).

The town of Craig is the largest town in Moffat County with a 2000 population of 9,190, an increase of 1,053 since 1990. Other communities in the county include Maybell (2000 population of 370), and Dinosaur (2000 population of 335), (US Census Bureau 2000). The 2009 US Census reports that there were 6,139 housing units in Moffat County that housed 4,983 households, indicating a vacancy rate of approximately 18.8 %. Approximately eight per cent of rental units were classified as vacant. There were 2.43 persons per household. Moffat County had a home ownership rate of 72.1% in 2000, well above the state average of 67.3 %. The median value of an owner occupied housing unit was $104,600, well below the state average of $166,600 (US Census Bureau 2001).

Economic Resources

The area of influence for economic resources is comprised of Routt and Moffat County. Moffat County is the county of residence for the majority of the mining personnel and supports most of the indirect employment that provides supplies and services to mine workers and their families.

Mining employment in Moffat County in 2009 was 1,000 full time jobs. (http://www.bls.gov/lau/laucntycur14.txt).

In 2009, Peabody Energy’s Twentymile Coal Co., Foidel Creek Mine employed an average of 490 full and part time workers with an annual payroll of approximately $28.3 million. Average annual mining wages and benefits for 2011 were $115,354 (Colorado Mining Association) and were more than twice the average wage for other employment sectors in the project area ($23,254) (Region 10 Review, 2003). Peabody Energy estimates that for every one coal job, 3 service-sector jobs are supported. The Twentymile Coal Foidel Creek Mine is expected to continue to spend many dollars locally for materials, supplies, and services. In addition, the Foidel Creek Mine would contribute royalty and tax payments to the local and national economy. Peabody contributes to local charities such as United Way, supports 4H, and also helps to sponsor local community events.

Protection of Children

Executive Order 13045, *Protection of Children from Environmental Health Risks and Safety Risks* (April 21, 1997), recognizes a growing body of scientific knowledge which demonstrates children may suffer disproportionately from environmental health risks and safety risks. These risks arise because (1) children’s bodily systems are not fully developed, (2) children eat, drink, and breathe more in proportion to their body weight, (3) their size and weight may diminish protection from standard safety features, and (4) their behavior patterns may make them more susceptible to accidents. Based on these factors, the

President directed each Federal agency to make it a high priority to identify and assess environmental health risks and safety risks that may disproportionately affect children. The President also directed each Federal agency to ensure that its policies, programs, activities, and standards address disproportionate risks to children that result from environmental health risks or safety risks.

Children are very seldom present at the coal mining facilities. On such occasions, the coal mining companies have taken and would continue to take precautions for the safety of children by using a number of means, including fencing, limitations on access to certain areas, and provision of adult supervision. No additional impact analysis is required.

3.4.2.2 Environmental Consequences

Proposed Action
Assuming that the lease modification is approved and the existing Twentymile Coal operations and facilities are used, there would be no new or added employment at the Twentymile Coal Foidel Creek Mine. Mining the coal reserves in the lease modification would increase the life of the mine. No additional housing or municipal services would be anticipated. Mining operations would be extended throughout the period necessary to mine the recoverable coal reserves. Mining of this lease modification would extend the annual payroll, taxes, royalty payments and other operating expenditures. Fifty percent of the royalties from the 8% of the value of the coal removed would be distributed to the federal treasury. The other 50 % would be returned to the state of Colorado with a portion of that percentage being returned to the county where the coal was mined. These proceeds from the coal royalties would be distributed on a grant-like basis to counties affected by energy resource development for community benefit projects.

No Action Alternative
Under the No Action Alternative, the primary impact would be that the estimated 644,000 tons of recoverable federal coal would be permanently bypassed. Mining of the reserves at the Twentymile Coal Foidel Creek Mine would continue at existing rates until the coal reserves are depleted. Reductions in jobs and associated salaries, local expenditures, royalty and tax payments would not be realized until after the reserves are depleted. The Federal government (US Treasury) and the State of Colorado would not receive the rents and royalties associated with mining the coal in the lease modification. Royalties from underground coal are 8% of the sales price. Using October, 2012 average weekly price of $35.75 per ton (U. S. Energy Information Administration), the lost revenues to the Federal government from the sale of 644,000 tons of recoverable coal at 8% would be $1,841,840.

3.4.2.2 Mitigation, both alternatives
None

3.4.2.3 Cumulative Impacts
The cumulative socioeconomic effects of continued mining would include an increased level of employment and tax revenues during the operation of the mine and the removal of that source of income when the mine is closed. Residential and other development activities would increase the local population and infrastructure in the area. The cumulative social and economic effects of past, present, and reasonably foreseeable actions relative to coal mining operations would be to extend the mining employment sector proportionately to the length of the remaining reserves.

CHAPTER 4– PUBLIC LAND HEALTH STANDARDS DETERMINATION

4.1 INTRODUCTION

In January 1997, the Colorado State Office of the BLM approved the Standards for Public Land Health and amended all RMPs in the State. Standards describe the conditions needed to sustain public land health and apply to all uses of public lands. The Twentymile coal lease modification area was assessed for compliance with the Colorado Standards of Public Land Health by an interdisciplinary team.

4.2 COLORADO PUBLIC LAND HEALTH STANDARDS

Standard 1 Upland soils exhibit infiltration and permeability rates that are appropriate to soil type, climate, land form, and geologic processes.

Finding of most recent assessment: The surface lands present within the proposed project area are private and have not been assessed.

Standard 2 Riparian systems associated with both running and standing water function properly and have the ability to recover from major disturbance such as fire, severe grazing, or 100-year floods.

Finding of most recent assessment: The surface lands present within the proposed project area are private and have not been assessed.

Standard 3 Healthy, productive plant and animal communities of native and other desirable species are maintained at viable population levels commensurate with the species and habitat's potential.

Finding of most recent assessment: The surface lands present within the proposed project area are private and have not been assessed.

Standard 4 Special status, threatened and endangered species (federal and state), and other plants and animals officially designated by the BLM, and their habitats are maintained or enhanced by sustaining healthy, native plant and animal communities.

Finding of most recent assessment: The surface lands within the proposed project area are private and have not been assessed.

Proposed Action: There are no federally listed threatened or endangered or BLM sensitive plant or animals species present within the proposed project area. For plants and animals, this standard does not apply.

Standard 5 The water quality of all water bodies, including ground water where applicable, located on or influenced by BLM lands will achieve or exceed the Water Quality Standards established by the State of Colorado.

Finding of most recent assessment: The surface waters present within the proposed project area are private and have not been assessed. Twentymile Coal LLC does have a groundwater monitoring implementation plan in effect. There is no indication that Twentymile Coal LLC is not meeting State of Colorado groundwater quality standards.

CHAPTER 5– COORDINATION AND CONSULTATION

PERSONS/AGENCIES CONSULTED: The LSFO staff consulted with the following tribes/agencies on the proposed action: Uintah and Ouray Tribal Council, Colorado Native American Commission, Colorado State Historic Preservation Office.

REFERENCES

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U. S. Census Bureau website, http://quickfacts.census.gov/qfd/states/08/08051.html. Last accessed 9/21/2012.

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APPENDIX A

Example Calculations

1.) Horsepower-hour Calculations for Underground Mobile Sources

Known Parameters:

1.) Foidel Mine's annual diesel fuel use 489,368 (Underground Equip.) gal	*source:	Peabody
2.) The average density of the diesel fuel is 7.11 lb/gal	*source:	LSD MSDS
3.) The LHV based energy density of the diesel fuel is 18,500 btu/gal	*source:	Ave. of literature
4.) Conversion: btu/hp-hr = 2,544.43	*source:	Common conversion
5.) CO_2 EF = 643.29 g CO_2/hp-hr	*source:	EPA Nonroad (2008a)
6.) Carbon content of diesel fuel = 2,778 g C/gal	*source:	40 CFR 600.113
7.) CO_2 : C Molecular Weight Ratio = 44/12 = 3.667 (unit less)	*source:	Periodic Table

Calculate Parameters (Underground Equipment Example):

1.) Total Available Energy of fuel =
489,368 gal x 7.1 lb/gal x 18,500 btu/lb .... = 64,278.48 MMbtu

2.) Energy Converter to HP (Energy IN) =
64,278,486,800 btu / 2,544.43 btu/hp-hr .... = 25,262,430 hp-hr

3.) Convert CO_2 EF of Diesel Fuel to C EF =
643.29 g CO_2/hp-hr x 3.667^{-1} .... =175.443 g C/hp-hr

4.) Derived hp-hr/gal of fuel from know Carbon Content of fuel =
2,778 g C/gal / 175.443 g C/hp-hr .... = 15.834 hp-hr/gal

5.) Derived hp-hr from fuel use (Energy Out) =
15.834 hp-hr/gal x 489,368 gal .... =**7,748,653 hp-hr**
....

6.) TE = Energy Out / Energy IN x 100% =
7,748,653 hp-hr / 25,262,430 hp-hr x 100% .... = **30.67%**

Conclusions:

The Thermal Efficiency of the underground equipment is approximately 30.67% based on the EPA Model data for CO_2. The value is realistic for working engines where hp is developed at various RMPs (based on loading and work cycles). Further the EPA Model takes this into account when developing the EFs (see Nonroad Technical Document NR009d "Exhaust and Crankcase Emission factors for Nonroad Engine Modeling – Compression- Ignition"). All emissions estimates are based on the EPA Nonroad Model emissions factors and the total hp-hrs derived in calculated parameter 5 for all underground equipment.

2.) Example Emissions Calculations for Underground Diesel Mobile Sources

General Equation for all Emissions:

Emissions (tons) = Total hp-hr (Energy Out[1]) x NR EF_E g/hp-hr x 453.6^{-1} g/lb x 2000^{-1} lb/ton

Where:

EF_E = Underground Equipment Emissions Factor

[1] For N_2O, substitute (Energy In). EF based on fuel use only.

A.) For NO_X (underground)

7,748,653 hp-hr x 8.561 g/hp-hr x 453.6^{-1} g/lb x 2000^{-1} lb/ton .... = ...73.12 tons

3.) Example Emissions Calculations for Gasoline Mobile Sources

Known Parameters:

1.) Foidel Mine's estimated annual unleaded fuel use 12,983 gal *source: Peabody Energy
2.) 2004 CAFE for LDGT = 20.7 miles per gallon (mpg) *source: NHTSA (2004)
3.) Emissions Factors (grams per vehicle mile traveled (g/VMT) are from 2003 IERA Mobile Source Emissions Tables 4.5, 4.6, 4.7, & 4.50
4.) Gasoline carbon content per gallon = 2,421 g C/gal *source: EPA 420-F-05-001, 2005
5.) CO_2 : C Molecular Weight Ratio = 44/12 = 3.667 (unit less) *source: Periodic Table

Calculate Parameters:

1.) Total Vehicle Miles Traveled (theoretical) =
12,983 gal x 20.7 mpg ....=268,745.8 miles

2.) CO_2 Emissions Factor =
12,983 gal x 2,421 g C/gal x 3.667 x $268,745.8^{-1}$ miles .... = ...428.87 g/VMT

General Equation for all Emissions:

Emissions (tons) = Total Annual Fuel Use (gal) x CAFE (mi/gal) x EF g/mi x 453.6^{-1} g/lb x 2000^{-1} lb/ton

A.) CO

12,983 gal x 20.7 mi/gal x 2.9 g/mi x 453.6^{-1} g/lb x 2000^{-1} lb/ton ....= 0.859 tons

B.) CO_2

12,983 gal x 20.7 mi/gal x 428.84 g/mi x 453.6^{-1} g/lb x 2000^{-1} lb/ton ....= 127 tons

Table A.1 Mobile Source Emissions Factors

Equipment Type[1]	SCC	PM	PM_{10}	$PM_{2.5}$	NMOG[3]	CO	NO_X	SO_2	CO_2	CH_4[4]	N_2O[5]
Underground Mining Equipment	2270009000	1.159	1.159	1.125	1.890	7.691	8.561	0.006	643.290	0.029	0.005
Passenger Vehicles[6]	LDGT	0.13	0.13	0.12	0.20	2.90	0.30	0.096	428.87	ND	ND

[1] All mining equipment Emissions Factors are g/hp-hr.

[2] Emissions factors from listed SCC equipment was averaged together to produce a composite emissions factor to represent likely equipment present at the facility. The individual equipment emissions did not statistically vary significantly within the model results. Data was not available for site fleet data to produce a facility specific weighted average.

[3] NMOG (Non-Methane Organic Gases) used to represent potentially reactive VOC species that may participate in ground level Ozone formation. NMOG is the sum of crankcase and exhaust emissions.

[4] CH4 is represented from TOG (Total Organic Gases) – NMOG. CH4 is the sum of crankcase and exhaust emissions.

[5] N2O factor derived from EPA Climate Leaders GHG Inventory Protocol (EPA430-K-08-004) Direct Emissions from Mobile Combustion Sources, Appendix A, Table A-6. N_2O factor reported as 0.08 g/kg of fuel combusted.

[6] Passenger vehicle emissions factors are in grams per vehicle mile traveled (g/VMT).