New Elk Coal Mine
Lease by Application

Federal Coal Lease (COC71978)

Environmental Assessment

DOI-BLM-CO-F020-2019-0014-EA

United States Department of the Interior

Bureau of Land Management

April 2019

Location:

New Elk Coal Mine, Las Animas County, Colorado

Applicant/Address:

New Elk Coal Company, LLC
12250 Highway 12
Weston, Colorado 81091

U.S. Department of the Interior
Bureau of Land Management
Royal Gorge Field Office
3028 E. Main Street
Canon City, Colorado 81212
Phone: (719) 269-8500

BLM

Royal Gorge Field Office

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ACRONYNMS AND ABBREVIATIONS

°C	degrees Celsius
°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
amsl	above mean sea level
Allen Mine	New Elk Coal Mine
APCD	Air Pollution Control Division
BLM	Bureau of Land Management
CAMx	Comprehensive Air Quality Model with Extensions
CARMMS	Colorado Air Resources Management Modeling Study
CBM	coal bed methane
CDC	Centers for Disease Control
CDNR	Colorado Department of Natural Resources
CDOT	Colorado Department of Transportation
CDPHE	Colorado Department of Public Health and Environment
CDRMS	Colorado Division of Reclamation, Mining and Safety
CF&I	Colorado Fuel & Iron
CFR	Code of Federal Regulations
cfs	cubic feet per second
CGS	Colorado Geological Survey
CH_4	methane
CMM	coal mine methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPW	Colorado Parks and Wildlife
EA	Environmental Assessment
EJ	environmental justice
EO	Executive Order
FCLAA	Federal Coal Leasing Amendments Act of 1976
FLPMA	Federal Land Policy Management Act of 1976
ft/day	feet per day
GHG	greenhouse gas
$GtCO_2$	gigatons of carbon dioxide
HAP	Hazardous Air Pollutant
HUC	hydrologic unit code
IPCC	Intergovernmental Panel on Climate Change
KRCRA	Known Recoverable Coal Resource Area

LBA	lease by application
lbs/hr	pounds per hour
LUA	Land Use Analysis
mg/L	milligrams per liter
MLA	Mineral Leasing Act of 1920
MPDD	mine plan decision document
mph	miles per hour
MT	metric tons
NAAQS	National Ambient Air Quality Standards
NECC	New Elk Coal Company, LLC
NEPA	National Environmental Policy Act
NO_x	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
OSMRE	Office of Surface Mining Reclamation and Enforcement
PM_{10}	particulate matter <10 micrometers in diameter
$PM_{2.5}$	particulate matter <2.5 micrometers in diameter
ppm	parts per millions
RCP	Representative Concentration Pathway
RGFO	Royal Gorge Field Office
ROD	Record of Decision
SAR	sodium adsorption ratio
SCC	social cost of carbon
SHPO	State Historic Preservation Office
SMCRA	Surface Mining Control and Reclamation Act of 1977
SO_2	sulfur dioxide
SPCC	Spill Prevention Control and Countermeasures Plan
TDS	total dissolved solids
tpy	tons per year
USC	United States Code
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geologic Survey
VOC	volatile organic compound
W/m^2	watts per square meter
WRCC	Western Regional Climate Center

CHAPTER 1 INTRODUCTION

1.1 Introduction and Background

The Bureau of Land Management (BLM) Royal Gorge Field Office (RGFO) is preparing an Environmental Assessment (EA) for a proposed coal lease on split-estate lands comprising three lease tracts located to the west of Weston, Colorado. New Elk Coal Company, LLC (NECC) has applied to the BLM for a 1,279-acre coal lease by application (LBA) COC71978 for lands adjacent to its existing underground New Elk Coal Mine (the Mine). The geographic area considered for the National Environmental Policy Act (NEPA) analysis for this EA is in Las Animas County, Colorado (**Figure 1-1**). The proposed LBA is for all economically mineable federal coal in the Blue and Maxwell Seams.

The proposed lease tracts are located in south-central Colorado approximately 26 miles west of Trinidad, north of State Highway 12 and the Purgatoire River, and within the Trinidad Known Recoverable Coal Resource Area (KRCRA). The KRCRA covers parts of Las Animas and Huerfano Counties. The proposed lease tracts contain federal coal only. All other minerals directly adjacent to the lease areas are privately owned. Furthermore, oil and gas within the lease areas is privately owned The land surface above the federal coal and directly adjacent are privately owned by several individuals or the State of Colorado (**Figure 1-2**).

There is no planned surface disturbance associated with the lease action. NECC submitted the LBA to obtain known recoverable federal coal reserves and to prevent bypass of those reserves. The BLM is required by law to consider leasing federal coal for maximum economic recovery.

If the BLM decides to lease the coal, it would then offer the lease by competitive sale. If NECC is the successful bidder at the lease sale, and the BLM issues the coal lease to NECC, the lease acreage would be added to the existing permit for the New Elk Mine (Colorado Division of Reclamation, Mining and Safety [CDRMS] permit no. C1981012). This permit is in active status and it is for an underground room-and-pillar coal mine operated without retreat mining methods. However, the mine has been inactive since 2014 because NECC's previous contract to sell the coal expired.

NECC plans to mine 73 million tons of coal at the New Elk Mine over the next 30 years. The federal coal underlying the lease application area contains an additional 8 million tons of recoverable coal available for the metallurgical coal market. These 8 million additional tons of federal coal would extend the projected 30-year lifespan of the mine by 5 years (to 35-year life of mine).

Historically, portions of the coal tracts of the proposed lease had been leased by Colorado Fuel & Iron (CF&I) and Basin Resources, the previous owners of the New Elk Coal Mine (formerly the Allen Mine mining the Allen coal seam).

The Allen (New Elk) Mine was originally opened in 1951 by CF&I to produce metallurgical coal for its steel works in Pueblo, Colorado. In 1981, the mine was sold to Wyoming Fuel Company, who installed a processing plant used to wash coal. After the New Elk Mine was closed in 1984, the plant was operated to wash coal from the Golden Eagle Mine and later to process coal from the Lorencito Canyon Mine. The federal coal lease was relinquished in 1996.

The New Elk Mine reinitiated mining in the Maxwell and Blue coal seams in 2009 as approved by a permit revision, but suspended operations in 2014. No mining is currently being conducted; however, the CDRMS permit remains in active status; therefore, mining can begin immediately once NECC enters into contract(s) to sell coal product from the Mine.

1.2 Purpose and Need

The purpose of the Proposed Action is to respond to NECC's request to lease federally owned coal reserves. These reserves are located adjacent to privately and state-owned coal that is currently under control by NECC at the New Elk Mine. This lease area would allow for: 1) an increase in total recoverable tons of coal, 2) an extension of the projected lifespan of the Mine, and 3) improved access to the privately or state-owned coal reserves (this lease is not required for access to the privately or state-owned coal reserves).

The need for the action is established by the BLM's responsibility under the Mineral Leasing Act (MLA) (30 United States Code [USC] 207) and Federal Land Policy Management Act (FLPMA), which states that public lands shall be managed in a manner that recognizes the nation's need for domestic sources of minerals (43 USC1701(a)(12)). Furthermore, FLPMA authorizes the BLM to manage the use, occupancy, and development of public lands through leases and permits (43 USC 1732).

This action is also needed to encourage the development of domestic coal reserves to meet future metallurgical coal needs. The federal coal reserves considered in this assessment are not accessible by any other mining operation. Thus, this action is needed to ensure that the coal is not bypassed and taxpayer revenues forgone.

1.3 Decision to be Made

The BLM will decide whether to lease the federal coal reserves in the LBA tracts and, if so, what terms, conditions, and stipulations would apply to the lease. Any terms, conditions, or stipulations would be identified in the decision document for this EA process.

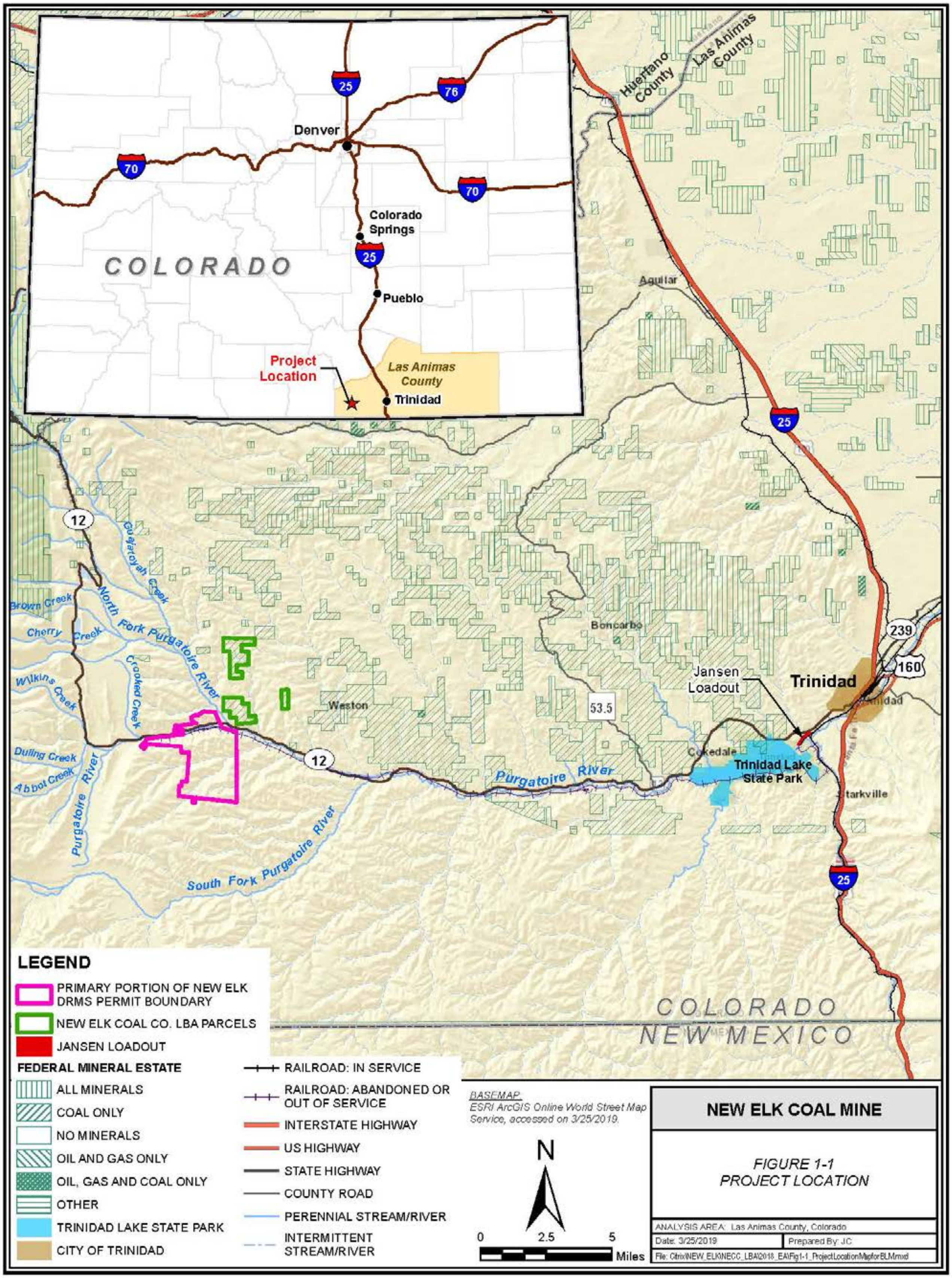
1.4 Plan Conformance and Relationship to Statutes and Regulations

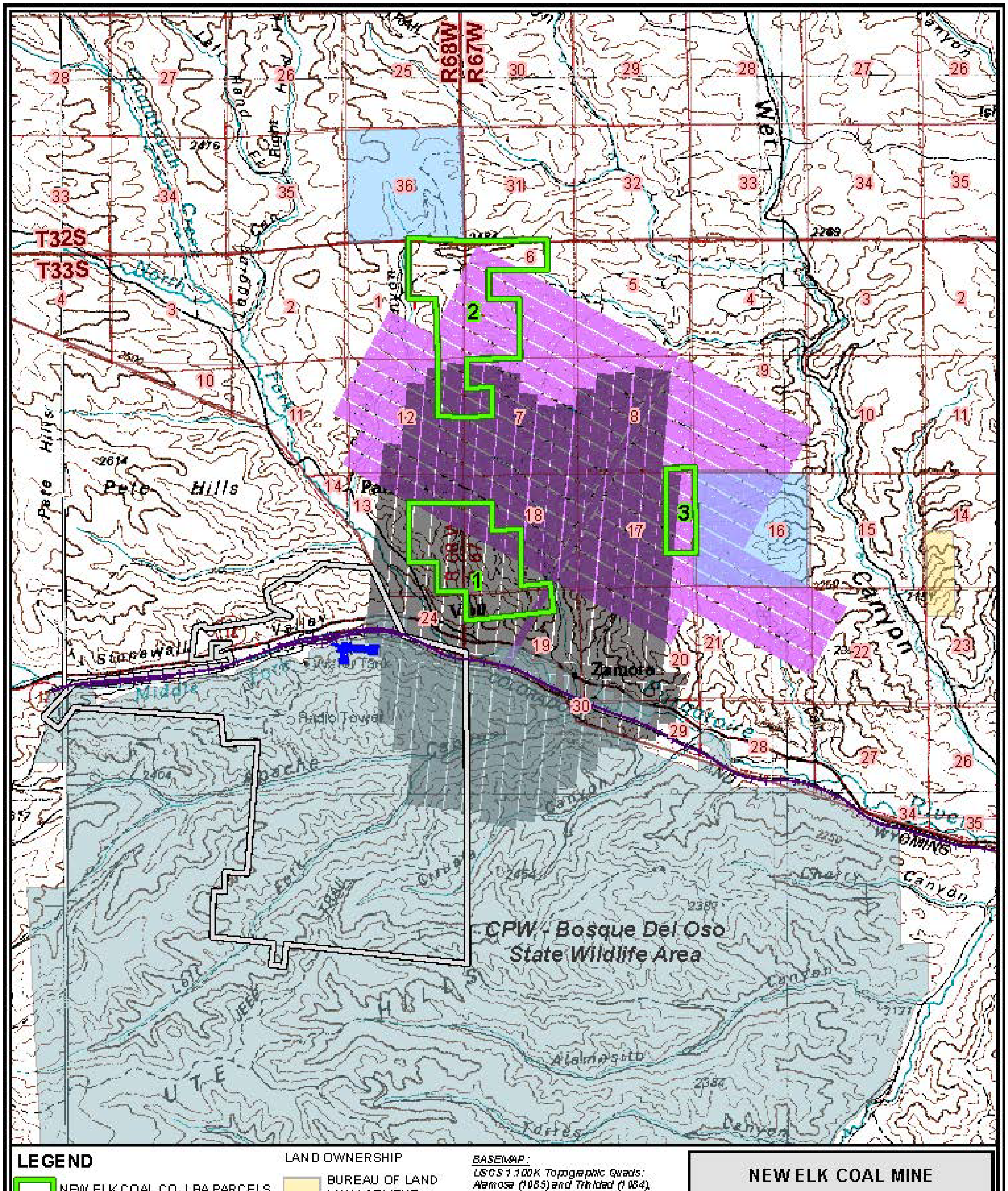
1.4.1 Plan Conformance or Land Use Analysis

The BLM, under the Secretary of the Interior, is the federal agency responsible for leasing federally administered coal. The Federal Coal Leasing Amendments Act (FCLAA) requires that coal leases be issued in conformance with a comprehensive land use plan or, where there is no federal interest in the surface and the coal resources are insufficient to justify the preparation costs of a comprehensive land use plan, a Land Use Analysis (LUA) [P.L. 94-377, Sec. 3 (3)(A) (i)).I].

This LBA is for coal resources located within the BLM's Royal Gorge Resource Area Resource Management Plan (BLM 1996a). These lands have been designated as suitable for coal mining. Parcels 1 and 3 are suitable for underground and surface mining, and Parcel 2 is suitable for underground mining only (**Figure 1-2**) (BLM 1996b, Record of Decision [ROD] Decisions 10-37 and 8-38).

Decision Language:
10-37: Coal resources on 52,980 acres will be available for further consideration for underground or surface mining.
8-38: Coal resources on 72,782 acres will be available for further consideration for underground mining only.


COLORADO
Denver
Colorado Springs
Pueblo
Project Location
Las Animas County
Trinidad
Huerfano County
Las Animas County
Aguilar
Boncarbo
Weston
Cokedale
Jansen Loadout
Trinidad
Trinidad Lake State Park
Starkville
Purgatoire River
North Fork Purgatoire River
South Fork Purgatoire River
Guajatoyah Creek
Brown Creek
Cherry Creek
Wilkins Creek
Crooked Creek
Duling Creek
Abbot Creek
COLORADO
NEW MEXICO
LEGEND
PRIMARY PORTION OF NEW ELK DRMS PERMIT BOUNDARY
NEW ELK COAL CO. LBA PARCELS
JANSEN LOADOUT
FEDERAL MINERAL ESTATE
ALL MINERALS
COAL ONLY
NO MINERALS
OIL AND GAS ONLY
OIL, GAS AND COAL ONLY
OTHER
TRINIDAD LAKE STATE PARK
CITY OF TRINIDAD
RAILROAD: IN SERVICE
RAILROAD: ABANDONED OR OUT OF SERVICE
INTERSTATE HIGHWAY
US HIGHWAY
STATE HIGHWAY
COUNTY ROAD
PERENNIAL STREAM/RIVER
INTERMITTENT STREAM/RIVER
BASEMAP:
ESRI ArcGIS Online World Street Map Service, accessed on 3/25/2019.
N
0 2.5 5 Miles
NEW ELK COAL MINE
FIGURE 1-1
PROJECT LOCATION
ANALYSIS AREA: Las Animas County, Colorado
Date: 3/25/2019
Prepared By: JC



T32S
T33S
R68W
R67W
CPW - Bosque Del Oso
State Wildlife Area
LEGEND
NEW ELK COAL CO. LBA PARCELS
PRIMARY PORTION OF NEW ELK DRMS PERMIT BOUNDARY
BLUE SEAM UNDERGROUND WORKINGS/DISTURBANCES
MAXWELL SEAM UNDERGROUND WORKINGS/DISTURBANCES
MINE WORKINGS
LAND OWNERSHIP
BUREAU OF LAND MANAGEMENT
PRIVATE
STATE
STATE WILDLIFE AREA
RAILROAD: ABANDONED OR OUT OF SERVICE
BASEMAP:
USGS 1:100K Topographic Quads: Alamosa (1985) and Trinidad (1984), Colorado.
N
0 3,000 6,000
Feet
NEW ELK COAL MINE
FIGURE 1-2
LAND OWNERSHIP
AND MINE PLAN
ANALYSIS AREA: Las Animas County, Colorado
Date: 4/4/2019
Prepared By: JC

1.4.2 Relationship to Statutes and Regulations

The proposed LBA and associated mining activities would be processed in accordance with all applicable laws, regulations, and orders including but not limited to:

- FLMPA of 1976
- MLA of 1920
- FCLAA of 1976
- Coal Leasing Amendments Act of 2005
- Surface Mining Control and Reclamation Act of 1977 (SMCRA)
- Applicable land use planning and coal leasing regulations at 43 Code of Federal Regulations (CFR) 1600 and 3400.

1.5 Scope of Analysis

The scope of analysis described in this EA is based on the issues discussed in **Section 1.6.3**, **Table 1-1**. While the scope of analysis focuses on the LBA tracts, surface facilities are also discussed because coal mined from the LBA tracts would be processed through these facilities, and coal mine waste associated with mining and processing would be permanently deposited in the refuse disposal facility (a permanent storage site for underground mine development and coal preparation plant waste materials). In addition, because NECC markets its coal for export to international steel companies, the exact locations of the international destinations are unknown and subject to market conditions. Coking of the coal mined from the LBA tracts at these end user points is incorporated into the scope of the analysis for greenhouse gas (GHG) emissions and climate change.

1.6 Scoping and Issues

1.6.1 Internal Scoping

An interdisciplinary team of cooperating agencies, including Office of Surface Mining Reclamation and Enforcement (OSMRE), the Colorado Department of Natural Resources (CDNR) (including CDRMS and Colorado Parks and Wildlife [CPW]), and BLM resource specialists, formulated issues associated with the Proposed Action through a series of conference calls and a kickoff meeting held in January 2018. Additional issues were identified through public scoping and subsequent discussions, conference calls, and meetings.

1.6.2 External Scoping/Public Involvement

Public scoping for this Project was open for comment from February 12 through February 26, 2019. Announcements for the scoping period were placed on the BLM ePlanning web site, in the Trinidad newspaper, and in a scoping letter that BLM mailed to the list of interested parties. The BLM received 18 comments during this period. Analysis of these comments is addressed in this EA. The issues identified through scoping are described in **Section 1.6.3**.

1.6.3 Issues

The issues for detailed analysis identified during public and agency scoping are summarized in **Table 1-1**. Impact indicators are used to describe the affected environment for each issue in Chapter 3, measure change, and assess the potential impacts of the alternatives.

Table 1-1 Issues Identified for Detailed Analysis

Issue	Issue Statement	Impact Indicator
1	How would mining, processing, transportation, and combustion of coal leased from the LBA tracts affect air resources and contribute to climate change?	Emissions of pollutants (tons)
2	What effect would leasing and mining the coal from the LBA tracts have on the quantity and quality of shallow groundwater accessed by residential and agricultural users?	Drawdown (feet) Concentration of solutes parts per million (ppm)
3	What effect would leasing and mining the coal from the LBA tracts and the permanent storage of coal mine waste have on water quality, terrestrial wildlife, and fisheries in the nearby Purgatoire River and wetland areas?	Changes to concentration of solutes (ppm)
4	How would the truck and train transportation of coal leased from the LBA tracts affect traffic, accidents, noise, road conditions, and wildlife populations?	Coal truck trips/unit trains per day added to existing conditions
5	How would leasing and mining of coal leased from the LBA tracts affect the socioeconomic conditions in the mine area?	Changes in social and economic values of the area

Issues evaluated and not discussed in further detail in this EA are described in **Table 1-2**.

Table 1-2 Issues not Included in Further Detailed Analysis in the Environmental Assessment

Issue	Issue Statement	Rationale for not Discussing Further in Detail in the EA
1	How would leasing and mining the coal affect fire management in the vicinity of the tracts?	There is no history of coal, methane (CH_4) gas, or rangeland wildfires from mining the privately or state-owned coal at the New Elk Mine and, as a result, no fire impacts are anticipated from leasing and mining the LBA tracts during the 5 additional years added to the mine plan. As a result, this issue is not carried forward for detailed analysis.
2	How would leasing and mining the coal affect the following resources directly above or in the immediate area of the lease tracts: listed species (federal and special status), migratory birds, invasive species/noxious weeds, soils, surface structures, recreation, vegetation, and the state wildlife area?	There would be no new surface disturbance from underground mining activities in the lease area and, because of the room-and-pillar mining method, there would be no subsidence or impacts related to ground surface settling. Other impacts on these resources are discussed in the issues analyzed in detail in Chapter 3. Therefore, this issue is not carried forward for detailed analysis.
3	How would leasing and mining the coal from the LBA tracts affect floodplain topography or flood predictions?	Because of the upland nature of the LBA tract area, there are no existing floodplains mapped within the tracts. With no surface disturbance proposed, no changes in water flows or topography would occur in the lease area. As a result, this issue is not carried forward for detailed analysis.
4	What impacts would generation, temporary storage, and disposal of solid and hazardous materials as a result of leasing and mining the coal have on people and the environment in the area?	Under the Proposed Action, there would be no change in or impacts from the amount or degree of annual generation of solid and hazardous materials (e.g., filters, lubricants, fuels, paints, solvents, coolant) at the mine for the additional 5 years of mining that would occur in the lease tract areas. All hazardous materials are monitored through the Spill Prevention Control and Countermeasures Plan (SPCC) according to 40 CFR §112 and are disposed of at approved off-site permitted facilities. This practice would continue under both alternatives. As a result, this issue is not carried forward for detailed analysis.

Table 1-2 Issues not Included in Further Detailed Analysis in the Environmental Assessment

Issue	Issue Statement	Rationale for not Discussing Further in Detail in the EA
5	How would leasing and mining the coal affect oil and gas development on and in the immediate vicinity of the tracts?	Conflicts between coal bed methane (CBM) development and coal mining can exist because CBM occurs in the mine plan area. There have been CBM wells drilled previously, and additional wells can be installed within the mine plan area. However, this issue is not carried forward for detailed analysis because there is no known interest in the CBM contained in the target coal seams within the lease tracts. Any existing wells or future wells installed in other strata that may contain CBM could be accommodated by the proposed room-and-pillar mining method.
6	How would subsidence from underground mining of the LBA tracts using room-and-pillar mining methods affect the availability of shallow groundwater in the vicinity of the tracts?	Based on the proposed room-and-pillar mine plan with no retreat mining or mining of pillars, no subsidence is anticipated from leasing and mining the coal in the LBA tracts. Based on the depth of mining and the mining method, no effects on water quality or quantity are anticipated from subsidence. As a result, this issue is not carried forward for detailed analysis. However, other effects on water quality or quantity of mining the lease tracts are discussed in Issue 3 below.
7	How would leasing and mining the coal affect minority or low-income populations in the vicinity of the tracts?	Consistent with Executive Order (EO) 12898 (59 Federal Register 7629, February 11, 1994) environmental effects to minority or low-income populations (including Native American Tribes) were considered. Las Animas County was used as the unit of analysis for determining presence or absence of environmental justice (EJ) "populations of concern," or communities and populations that should be considered under the EO. During the Project Scoping period, communities in the area were invited to provide comments and issues about the proposed lease to be analyzed in this EA. The communities will also have the opportunity to comment on this Draft EA as it is released for review and public comment. The total population in Las Animas County is approximately 47 percent aggregate minority. Approximately 22 percent of Las Animas County residents live below the poverty line (U.S. Census Bureau 2018). The BLM has determined that there are minority and low-income communities and populations in Las Animas County that should be considered "EJ populations" for purposes of complying with the EO. However, no disproportionate impacts would occur because there would be minimal impacts from 5 additional years of mining. There would be no surface disturbance. In addition, controls measures applied to maintain air quality, water quality and human health in the mine area would continue during the 5 additional years of mining. Consequently, EJ issues associated with leasing and mining the LBA tracts are not carried forward for detailed analysis.
8	Will the undertaking directly, indirectly, or cumulatively, and adversely, affect any historic properties present in the area of potential effects?	Because the leasing of parcels does not involve ground disturbance, it will have no effect on historic properties. In an informational letter dated August 29, 2018, BLM notified the Colorado State Historic Preservation Office (SHPO) of these determinations (see CR-RG-18-107 L).

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CHAPTER 2 ALTERNATIVES

2.1 Status

The New Elk Mine is an underground coal mine located approximately 6 miles west of the Town of Weston, Colorado on State Highway 12. The mine is currently idle, with the portal to the Blue Seam temporarily sealed. Surface facilities and privately and state-owned coal reserves are being maintained in the anticipation of reopening when NECC successfully negotiates coal purchase contracts.

2.2 Reserves

The Blue and Maxwell Seam coals to be mined are classified as metallurgical-grade coals best targeted for use in the production of steel from iron ore. Primary met-coal markets include China, Korea, Japan, and Brazil but the location of coal use would depend on a signed coal contract. Privately and state-owned coal reserves currently held by NECC total more than 73 million recoverable tons. The LBA is estimated to recover reserves totaling 8 million tons and can be accessed with the current New Elk Mine plan shown on **Figure 2-1,** as a permit revision is approved by CDRMS. Acquisition of the BLM lease would: 1) increase recoverable reserves by approximately 11 percent, 2) provide better access to some of the existing privately and state-owned reserves, and 3) extend the projected mine life by 5 years to a 35-year life of mine.

2.3 Mine Plan

The current NECC mine plan for privately and state-owned coal reserves represents enough coal for at least 30 years of mining at 1.5 to 2.0 million saleable tons per year (tpy). Under the current mine plan, tonnage varies per year depending on market demand. Depth to the coal depends on dip of the seams to the northeast and the rising overlying topography to the northeast. Depth of the Blue Seam at the southern lease Parcel 1 is approximately 430 feet and 700 feet to the Maxwell Seam. Coal depth to the Maxwell Seam in the northeast portion of the Lease Tracts is approximately 1,500 feet. Underground mining is by the room-and-pillar method with no retreat extraction or longwall mining planned. Once NECC secures coal purchase contracts, it would restart mining in the Blue Seam, with mains development progressing eastward from existing workings and production panels developed south off from these mains.

Under the current mine plan, during year 3, NECC plans to advance mains development northward to access the majority of the Blue Seam reserves (**Figure 2-1**). The locations of these mains depend on NECC successfully acquiring the lease requested in its LBA as well as the associated mine plan within this 3-year timeframe.

The ideal location for NECC to develop the north mains is to advance through the southernmost BLM tract. Mining in the Blue Seam is scheduled to continue through year 20 of mining. If NECC is successful in acquiring this lease, NECC would begin mining the federal coal under the LBA in year 3. The timing of coal production on the three lease tracts would vary intermittently over the life of the Mine as shown by their locations in the mine plan.

Future mining includes advancing rock tunnels approximately 270 feet from the Blue Seam down to the Maxwell Seam after year 5 of mining. As reserves in the Blue Seam are depleted, the Maxwell Seam becomes the primary focus of production through year 30 and the end of mining as currently planned. If some reserves remain at the end of 30 years, mining could be extended to maximize recovery.

2.4 Resumption of Operations

All surface facilities necessary for restarting operations have been maintained since the mine was idled in 2014 in anticipation of new coal purchase contracts and renewed production. Initial start-up would require reestablishing ventilation at the portal using existing equipment in the surface facilities area and providing power to the Blue Seam underground mine workings. Once ventilation is established, mining equipment can be advanced into the underground working area. NECC has developed a mine plan for the surrounding coal reserves as discussed in the No Action Alternative section of this EA. Therefore, NECC can resume mining at any time; it is not dependent on obtaining the LBA reserves.

Existing surface facilities are adequate to support initial mining production. Over the course of the first 1 to 5 years of mining, the following surface improvements would occur:

- Final permitting and construction of a new sewage treatment plant in year 1 of the mine plan
- Final permitting and construction of a new preparation plant and waste-rock refuse disposal area in years 3 to 5 of the mine plan
- Reinstallation of the rail line from the mine to the Jansen Railroad Loadout near Trinidad, Colorado once enough coal sales are secured to justify rail haulage versus truck transportation on State Highway 12 (currently thought to be 1 million tpy of coal shipments).

These projects are necessary for continued mining and are not dependent on obtaining the LBA tracts. Therefore, they are not analyzed as part of the Proposed Action but are considered under Cumulative Impacts. No other new surface facilities are anticipated at this time.

2.5 No Action Alternative

The BLM would deny the LBA; thus, federal coal reserves within the 1,279-acre tracts would not be recovered. If the LBA is denied, NECC could mine the 73 million recoverable tons of privately and state-owned coal surrounding the LBA tracts once it obtains coal purchase contracts and resumes operations (**Figure 2-1**). The mining operation at the New Elk Mine would occur for approximately 30 years.

Due to the geologic features of the LBA tracts (amount of recoverable coal and proximity to privately and state-owned coal), as well as the room-and-pillar mining method used in New Elk Mine, the 1,279-acre federal tracts would not be mined in the foreseeable future and may become unmineable. Approximately 8 million tons of recoverable federal coal deposits in the LBA would be bypassed and likely not developed due to the following constraints: 1) depth of coal, 2) limited acreage (1,279 acres split into three tracts), 3) quantity of recoverable coal, and 4) difficulty of future mine access (directly adjacent coal reserves are privately and state-owned and currently owned or leased by NECC). Bypassing the LBA would render these tracts operationally and geologically isolated. Any future attempt at recovery of these federal coal deposits would be challenging from an operational perspective. Installation of proper ventilation and access shafts on these small tracts would be cost-prohibitive for the amount of coal to be recovered.

2.6 Proposed Action Alternative

Under the Proposed Action, the BLM would approve coal mining of 1,279 acres within the three tracts for the LBA and, as a result, NECC would mine the coal using room-and-pillar underground mining methods with no retreat mining; pillars would be left in place. The federal coal reserves proposed for lease by NECC lie north of and adjacent to existing privately and state-owned coal reserves controlled by NECC and logically provides for maximum economic recovery of federal coal by the New Elk Mine. Both the Blue and Maxwell Seams are economically mineable reserves within the LBA area. **Figure 1-2** shows the (proposed) mine plans for the Blue and Maxwell Seams and the locations of the LBA tracts in relation to these plans. Securing the BLM lease improves the access for NECC to develop and mine other privately and state-owned coal reserves currently controlled by NECC.

Mining the BLM tracts would not result in any additional surface disturbance. The mining methods proposed would prevent subsidence and provide protection for water and other surface resources. The access points for all the coal reserves are at the existing portals at the New Elk Mine surface facilities area. Existing land uses of rangeland, residential subdivision development, and wildlife habitat in the lease tract area would be maintained. CBM operations and future development would continue, as coal production using room-and-pillar mining could avoid these wells.

2.7 Alternatives Considered but Dismissed

This section describes alternatives to the Proposed Action that will not be analyzed in detail because they do not meet the criteria listed in 40 CFR 1502.14.

2.7.1 Reduced Recovery

As part of the analysis, the BLM considered reducing the amount of coal to be recovered within the three tracts or removing one or two of the tracts included in the LBA. This alternative was not carried forward because there would be no appreciable differences in effects, it would not maximize recovery in the lease area, and it would not resolve any conflicts that are not resolved under the existing Proposed Action. Mining of the three proposed parcels varies spatially and temporally beginning in year 3 of the mine plan because the three parcels are separated by private coal and contain varying portions of the Blue and Maxwell Seams, which are targeted for mining.

2.7.2 Longwall Mining

As part of the analysis, the BLM considered the longwall mining method. Longwall mining has better coal recovery compared to the room-and-pillar method; however, this alternative was not carried forward because there would be subsidence impacts to surface resources that could not be mitigated.

2.7.3 Retreat Mining

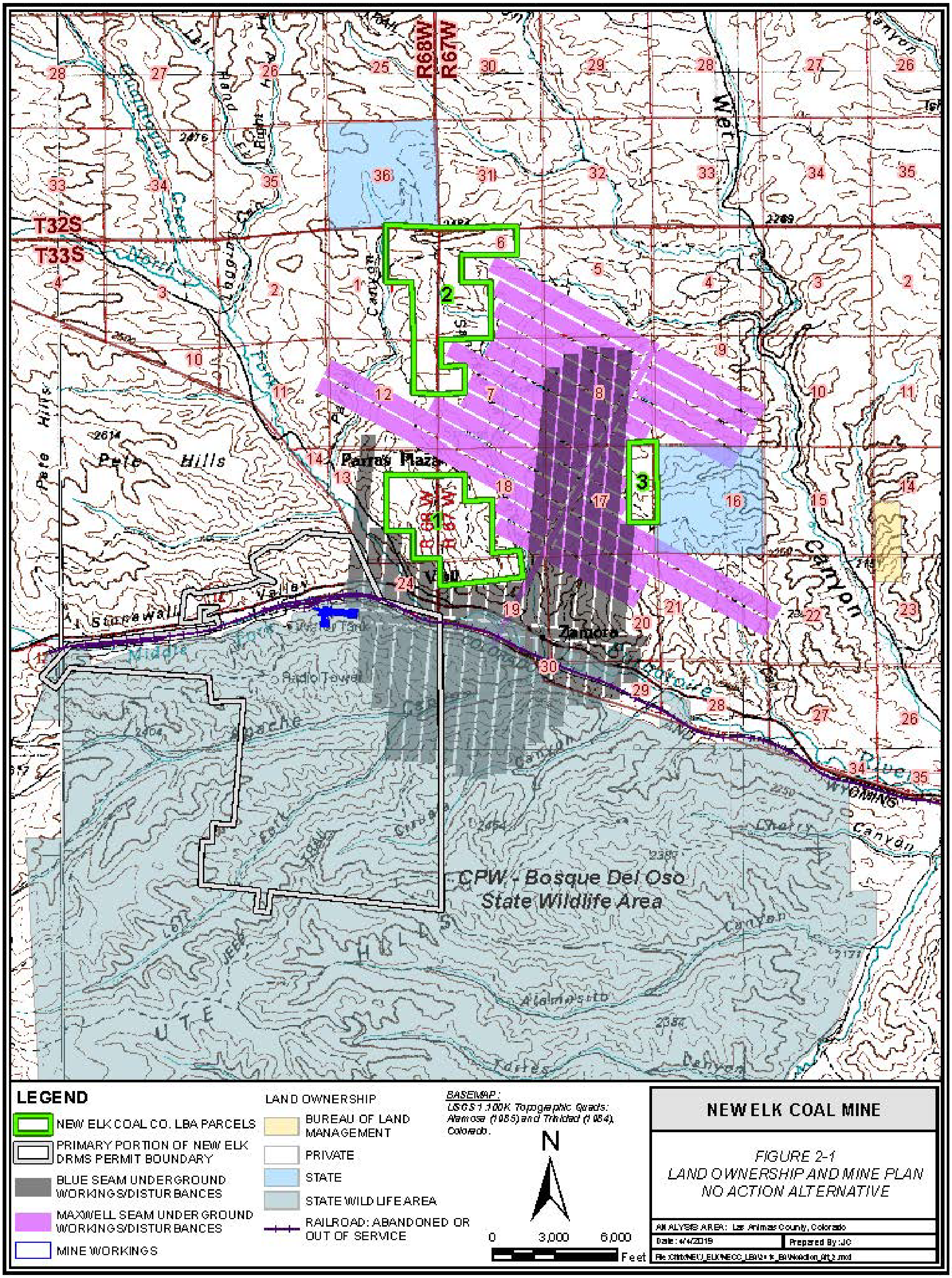
As part of the analysis, the BLM considered the retreat mining method, where pillars would be mined during the later years of the mine plan. Retreat mining has better coal recovery compared to the proposed room-and-pillar method; however, this alternative was not carried forward because there would be subsidence impacts to surface resources that could not be mitigated, similar to the longwall mining option.

2.7.4 Methane Flaring

As a result of coal extraction, methane trapped in the coal seam is released. The amount of methane present varies with the geologic setting of the coal bed. As part of the analysis, the BLM considered capturing methane, but did not carry this alternative forward because the methane from the recovered coal would be liberated and released into the atmosphere through the ventilation system. The volume and concentrations of methane in the vent air would not be sufficient to allow flaring. From the coal left in place, methane would continue seeping out of natural fractures (cleats and joints) and new fractures caused by mining activity, but the volume would not be sufficient to allow flaring, therefore making this alternative unfeasible.

2.7.5 Methane Capture Wells

In advance of mining the coal in the two seams, methane could be extracted through the installation of wells. Any methane captured would be piped to a flare unit or gathered for power generation or other uses. As part of the analysis, the BLM considered installing wells to capture methane, but did not carry this alternative forward because installing wells and surface infrastructure to handle the methane would cause surface disturbance and impacts to surface resources. Wells are not typically associated with the proposed room and pillar mine methods as no subsidence occurs to liberate the methane. In addition, The volume and concentration of methane released from the lease tracts would not allow sufficient funds for infrastructure installation, therefore making this alternative uneconomical.



LEGEND
NEW ELK COAL CO. LBA PARCELS
PRIMARY PORTION OF NEW ELK DRMS PERMIT BOUNDARY
BLUE SEAM UNDERGROUND WORKINGS/DISTURBANCES
MAXWELL SEAM UNDERGROUND WORKINGS/DISTURBANCES
MINE WORKINGS
LAND OWNERSHIP
BUREAU OF LAND MANAGEMENT
PRIVATE
STATE
STATE WILDLIFE AREA
RAILROAD: ABANDONED OR OUT OF SERVICE
BASEMAP: USGS 1:100K Topographic Quads: Alamosa (1985) and Trinidad (1984), Colorado.
N
0 3,000 6,000 Feet
NEW ELK COAL MINE
FIGURE 2-1
LAND OWNERSHIP AND MINE PLAN
NO ACTION ALTERNATIVE
ANALYSIS AREA: Las Animas County, Colorado
Date: 4/4/2019
Prepared By: JC
CPW - Bosque Del Oso State Wildlife Area
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CHAPTER 3 ISSUES ANALYSIS

3.1 Past, Present, and Reasonably Foreseeable Future Actions

Past, present, and reasonably foreseeable future activities in the coal lease area considered in the impact assessment include coal mining, oil and gas development, agricultural and ranching, residential subdivision development, and recreational activities. Impacts for these activities are described in the cumulative impacts section for each issue.

3.2 Introduction

This chapter describes the existing conditions relevant to the issues presented in **Table 1-1** and discloses the potential direct, indirect, and cumulative impacts of the No Action and Proposed Action alternatives on those issues.

Potential impacts discussed in this chapter are described in terms of duration and intensity. Periods of duration are defined as short-term – 5 years or less, or long-term - more than 5 years. The thresholds of change for the intensity of a potential impact are defined as follows:

Negligible – A change in current conditions that is too small to be physically measured using normal methods or perceptible to a trained human observer. There is no noticeable impact on the natural or baseline setting. There are no required changes in management or utilization of the resource.

Minor – A change in current conditions that is just measurable with normal methods or barely perceptible to a trained human observer. The change may impact individuals of a population or a small (<10 percent) portion of a resource but does not result in a modification of the overall population or the value or productivity of the resource. There are no required changes in management or utilization of the resource.

Moderate – An easily measurable change in current conditions that is readily noticeable to a trained human observer. The change impacts 25 to 75 percent of individuals of a population or similar portion of a resource, which may lead to modification or loss in viability in the overall population, or the value or productivity of the resource. There are some required changes in management or utilization of the resource.

Major – A large, measurable change in current conditions that is easily recognized by all human observers. The change impacts more than 75 percent of individuals of a population or similar portion of a resource which leads to significant modification in the overall population, or the value or productivity of the resource. There are profound or complete changes in management or utilization of the resource.

No additional mitigation measures were identified as necessary following the analysis of each issue.

3.3 Issue 1: How would Mining, Processing, Transportation, and Combustion of Coal Leased from the LBA Tracts Affect Air Resources and Contribute to Climate Change?

Leasing and mining the LBA tracts would result in pollutant emissions. Mining of the LBA tracts would extend the projected 30-year lifespan of the mine by approximately 5 years for a 35-year mine life. As the three lease parcels are in different areas of the mine plan, the federal coal would be intermittently mined over the life of the mine if the lease is issued to New Elk. Emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter with an aerodynamic diameter of 10 microns or 2.5 microns or less (PM_{10} and $PM_{2.5}$, respectively), and GHGs would be produced as a result of the mining activities. NO_x, CO, VOC, SO_2, PM_{10}, and $PM_{2.5}$ are collectively known as criteria pollutants. Criteria pollutant emissions are estimated for emission sources and activities related to mining and transport of coal from the LBA tracts. GHG emissions are estimated for combustion of petroleum fuels, mine methane ventilation, and coal coking. Coal heated in an oxygen-free atmosphere produces a high carbon content mass called coke used in iron and steel industry processes. Mining activities would consist of equipment fuel combustion, underground mining, coal handling/loading, fugitive dust emissions, and hauling the coal on unpaved mine roads.

NECC markets its coal for export to international steel companies for use as metallurgical coal. Coal would be transported by truck to the Jansen Railroad Loadout near Trinidad, Colorado and loaded into rail cars for transport by locomotive to a domestic shipping port. At the shipping port, coal would be loaded into cargo ships for ocean-going transport to an international destination port. For the purposes of this evaluation, because contracts are not yet in place for the purchase of the coal, it was assumed that the coal would be transported by rail a distance of 1,500 miles to a domestic shipping port and then shipped a distance of 10,000 miles to an international destination, where the coal would be combusted to coke for use in the production of steel or iron at an unknown location. Pollutant emissions produced as a result of combustion of the mined coal would occur at the same time as mining occurs. Pollutant emissions for each activity were calculated annually over a 5-year period. GHG emissions are given in units of metric tons (MT) of carbon dioxide equivalent (CO_2e).

3.3.1 Affected Environment

The Mine area is in western Las Animas County, which lies within the South-Central Region of Colorado for air quality planning. This area complies with federal air quality standards for ozone, PM_{10}, $PM_{2.5}$, CO, and SO_2 (U.S. Environmental Protection Agency [USEPA] 2018).

The regional climate is characterized as a semiarid (dry and cold), mid-continental climate regime and is typified by dry, sunny days, clear nights, and wide daily temperature variations. The nearest long-term meteorological station with both historical and recent data is at Trinidad, Colorado (1948-2008), located approximately 25 miles east of the Project area at an elevation of 6,030 feet above mean sea level (amsl) (Western Regional Climate Center [WRCC] 2019). The annual average total precipitation at Trinidad is 15.55 inches. An average of 50.8 inches of snow falls during the year. The region has cool temperatures, with the average temperature (in degrees Fahrenheit [˚F]) ranging between 18.9˚F and 48.5˚F in January to between 57.3˚F and 86.8˚F in July. Most of the wind direction is out of the west-northwest to west-southwest.

3.3.2 Environmental Impacts

3.3.2.1 Impacts of the No Action Alternative

Under the No Action Alternative, NECC would mine privately and state-owned coal tracts for the estimated operational life of the mine (approximately 30 years). During this time, emissions of criteria pollutants and GHGs would occur at the Mine. Except for some of the particulate matter (fugitive dust), all the directly emitted criteria pollutants from the New Elk Mine's operations are from fuel combustion sources, such as mobile mining equipment, haul trucks, and stationary sources such as emergency generators and coal conveyance systems. Many of these sources would also produce GHG emissions as well. Direct and indirect emissions resulting from New Elk's mining activities are summarized in **Table 3-1** and **Table 3-2**. Detailed information for all aspects discussed below is provided in **Appendix A**.

Table 3-1 Projected Direct Emissions (tons/year)

Source	PM_{10}	$PM_{2.5}$	VOC	NO_X	CO	SO_2	CO_2e[1]	CO_2	N_2O	CH_4
Generator Engine – Propane	5.58E-07	5.58E-07	0.011	0.030	2.29E-03	4.26E-06	3.45	3.75	1.79E-04	3.57E-05
Generator Engine – Gasoline	2.44E-04	2.44E-04	0.0051	3.72E-03	2.35E-03	2.00E-04	0.46	0.50	2.12E-05	4.25E-06
Nonroad Mobile Diesel Engines	1.62	1.62	15.38	32.37	283.24	0.6	51,595	56,167	2.28	0.46
Mine Ventilation	7.38	7.38	NA	NA	NA	NA	1,124,730	NA	NA	49,578
Worker Commutes	51.83	5.49	1.20	1.20	15.81	0.01	1,120	1,224	0.03	0.05
Surface Stationary Point Sources	4.5	0.69	NA	NA	NA	NA	NA	NA	NA	NA
Surface Dozing/Stockpiles	26.95	4.09	NA	NA	NA	NA	NA	NA	NA	NA
Surface Unpaved Roads	10	1	NA	NA	NA	NA	NA	NA	NA	NA
Truck Transport to/from Jansen Rail Yard	1.26	1.15	2.64	53.3	15.08	0.31	6,352	6,990	0.029	0.031
Subtotal of Direct Sources	**103.53**	**21.42**	**19.23**	**86.91**	**314.13**	**0.91**	**1,183,800**	**64,385**	**2.34**	**49,579**

Notes:
1 CO_2e units are metric tons

Table 3-2 Projected Indirect Emissions (tons/year)

Source	PM_{10}	$PM_{2.5}$	VOC	NO_X	CO	SO_2	CO_2e[1]	CO_2	N_2O	CH_4
Jansen Rail Yard Activities and Loading	6.21	0.71	0.5	1.06	9.29	1.96E-02	1,691	1,841	0.075	0.015
Rail Transport to Domestic Port	22.74	22.05	37.35	936.69	283.74	0.85	83,915	91,642	2.18	7.27
Domestic Port Activities & Loading	6.21	0.71	0.5	1.06	9.29	1.96E-02	1,691	1,841	0.075	0.015
Ship Transport to International Port	65.37	59.81	69.55	1,250	153	552.2	1,067,433	1,163,712	33.94	99.40
International Port Activities & Loading	6.21	0.71	0.5	1.06	9.29	1.96E-02	1,691	1,841	0.075	0.015
Coal Coking (combustion)	NA	NA	NA	NA	NA	NA	6,243,039	6,834,384	96.98	661.86
Subtotal of Indirect Sources	**106.74**	**84.00**	**108.4**	**2,189.44**	**464.59**	**553.11**	**7,399,460**	8,095,262	133.32	768.58

Notes:
1 CO_2e units are metric tons

To estimate the potential impacts of the Mine's emissions on nearby receptors, the BLM provided a screening analysis using USEPA's regulatory atmospheric dispersion model, AERMOD. AERMOD is a steady-state dispersion model designed to estimate short-range (up to 50 kilometers) dispersion of air pollutant emissions from stationary industrial sources. Results of the screening analysis are summarized in the **Table 3-3** below and are compared to the National Ambient Air Quality Standards (NAAQS) established by USEPA.

Table 3-3 Projected Model Impacts

Source	Pollutant	Modeled Emission Rate (lbs/hr)	Maximum 1-hr Concentration (μg/m3)	% NAAQS	Standard	% NAAQS	Standard
Point	CO	45.39	259.4	0.65	1-hr	2.33	8-hr
	PM_{10}	2.625	15.0	1.0	Annual	NA	NA
	$PM_{2.5}$	2.625	15.0	12.5	Annual	25.72	24-hr
	NO_X	5.19	29.65	15.69	1-hr	5.59	Annual
Volume	CO	34.82	132.3	0.33	1-hr	1.19	8-hr
	PM_{10}	10.39	59.38	3.96	Annual	NA	NA
	$PM_{2.5}$	1.62	9.26	7.72	Annual	15.87	24-hr
	NO_X	3.98	22.74	12.03	1-hr	4.29	Annual

The modeling results show that the mining operation would not cause an exceedance of the NAAQS for any pollutant.

No modeling analysis is being provided for the indirect emissions sources because their locations are presently unknown. However, it is unlikely that the minor amount of pollutants shown above for the stationary locations would have a significant impact on air quality. All transport-related emissions would have a similar negligible impact because these emissions would be spread across what could potentially be thousands of miles, most of which could be on the open ocean, far removed from receptor populations.

With respect to any potential ozone formation, the Mine is not a significant source of ozone precursors (NO_X and VOC), and therefore is not expected to contribute significantly to any regional ozone formation potential.

The total Hazardous Air Pollutants (HAP) emissions from all sources at the Mine are approximately 8.68 tons per year and are estimated to be emitted at a rate of 0.7 gram per second. The potential human health impacts associated with HAP emissions would be negligible considering the minor magnitude of these emissions, air dispersion before reaching a fence line, and distance to the nearest potential receptor.

Over the projected 30-year mine life, the No Action Alternative mining activities would contribute 257.42 million metric tons of GHGs to the atmosphere on a CO_2e basis. There are currently no climate analysis tools capable of estimating the actual climate response attributable to a specific activity. Alternatively, the approach for assessing climate impacts is to use decision scope emissions as a surrogate (or proxy) for describing the known (modeled) climate impacts associated with various global emissions scenarios. Climate change is fundamentally a cumulative issue with global scope, and all GHGs contribute incrementally to climate change. Given the cumulative nature of GHGs and the climate change issue, and a lack of No Action Alternative specific impacts, an emissions analysis and description of anticipated changes and impacts from climate change is presented in the Cumulative Impacts section below.

3.3.2.2 Impacts of the Proposed Action Alternative

All of the effects of mining, processing, transport, and coking of coal described for the No Action Alternative would occur under the Proposed Action Alternative. The Proposed Action would have the practical effect of extending the Mine's life by an additional 5 years due to the availability of the federal coal. Mining the federal coal is not expected to alter how New Elk would maintain operations; therefore, emissions levels can be expected to remain at the rates shown above for the No Action Alternative. Similarly, the impacts of the emissions from operational activities would be the same as those associated with the No Action Alternative.

However, the additional federal coal made available under the approval of the Proposed Action would amount to additional GHG loading of the atmosphere. At projected mining rates, the total direct and indirect GHG emissions from 5 additional years of mining under the Proposed Action would contribute an additional 37.28 million metric tons of GHG on a CO_2e basis.

3.3.2.3 Cumulative Impacts

Cumulative impacts of mining activities combined with other industrial uses and emissions from coalbed methane development, oil and gas development, construction/operation of the New Elk railroad, agriculture, ranching, residential subdivision developments, and recreational activities would cause negligible to minor degradation in regional air quality. Construction/operation of the New Elk railroad at higher coal production levels would reduce air emissions for coal transport relative to those generated by trucks transporting coal to the Jansen Rail Yard because locomotives transport more weight per gallon of diesel fuel than trucks. With the exception of the additional GHG loading from making the LBA tracts available, the effects described in this section are applicable to both the No Action Alternative and the Proposed Action Alternative. A summary of the cumulative impacts assessment is provided below. Detailed information is provided in **Appendix A**.

<u>CARMMS.</u> To examine potential cumulative air quality impacts from activities that it authorizes, the BLM initiated the Colorado Air Resources Management Modeling Study (CARMMS) (BLM 2017). The study version 2.0 was primarily concerned with assessing statewide impacts of projected oil and gas development (both federal and fee [i.e., private]) out to year 2025 for three development scenarios (low, medium, and high). However, CARMMS also incorporated coal resources with a mining scenario based on each mine's maximum allowable emissions rate while acknowledging that most mines in Colorado are not currently producing at their maximum authorized capacities. CARMMS used the Comprehensive Air Quality Model with Extensions (CAMx) photochemical grid model to conduct the study.

Results of the study indicate that the PM_{10} and $PM_{2.5}$ contributions from all the mines appear to be low around the New Elk facility. NO_2 and ozone are also equally minor impactors, although it is noted that the ozone predictions are a function of the mine's direct NO_x and VOC contributions and does not include any potential coal mine methane (CMM) VOCs because they are unknown. With fewer NO_X and VOC emissions than that of the high oil and gas scenario, the Mine is not expected to contribute significantly to direct ozone formation.

Overall, the CARMMS data suggest that air quality impacts surrounding the Mine are essentially negligible.

<u>Greenhouse Gas Emissions Analysis.</u> Climate change is fundamentally a cumulative issue with global scope, and all GHGs contribute incrementally to climate change, regardless of the emissions' location, duration, or source type. The multitude of interwoven natural systems and feedback mechanisms that contribute to climate variability over the entirety of the Earth makes analysis of this issue exceptionally complex. Climate scientists provide for analysis by modeling changes to these systems in response to a range of global emissions scenarios known as Representative Concentration Pathways (RCPs). RCPs are

not fully integrated scenarios of climate feedback, policy, emissions limits, thresholds, or socioeconomic projections, but rather, a consistent set of cumulative emissions projections (out to year 2100) of only the components of radiative forcing that are meant to serve as input for climate and atmospheric chemistry modeling. The following are four primary pathways that climate scientists have used for assessment in numerous climate models:

RCP2.6 **-** Very low emissions levels leading to peak in radiative forcing at 3.1 watts per square meter (W/m^2) by mid-century, returning to 2.6 W/m^2 by 2100, where GHG emissions (and indirectly emissions of air pollutants) are reduced substantially over time.

RCP4.5 **-** Stabilization scenario where total radiative forcing is stabilized at 4.5 W/m^2 before 2100 by employment of a range of technologies and strategies for reducing GHG emissions. This pathway forecasts that global emissions will increase until about 2040, with actual stabilization occurring between 2030 and 2050. Starting in 2050, emissions would start to decline at rates commensurate with the 2.6 pathway until 2080, when emissions stabilize again through the end of the century.

RCP6.0 **-** Stabilization without overshoot pathway with radiative forcing of 6 W/m^2 after 2100 by employment of a range of technologies and strategies for reducing GHG emissions. Emissions of both CH_4 and N_2O are more or less stable throughout the century and do not contribute significantly to additional radiative forcing, while emissions of CO_2 grow steadily until 2080 before declining.

RCP8.5 **-** Increasing emissions over time leading to very high GHG concentration levels and radiative forcing of 8.5 W/m^2 in 2100. This pathway assumes that emissions trajectories follow a historical growth curve and is representative of the high range of non-climate policy scenarios or a worst-case scenario that assumes unabated emissions.

<u>The Carbon Budget.</u> A growing body of analysis on coupled climate-carbon models have shown that temperature is closely related to the total amount of CO_2 emissions released over time, where the cumulative emissions (i.e., the area under the curve), rather than the timing or shape of the emissions curve, is more important for peak warming estimates. This also means that mitigation requirements can be quantified using a budget approach, or the amount of CO_2 emissions that can still be emitted (cumulatively) relative to a target temperature (global mean temperature increase) with varying degrees of probability that such a budget will limit warming to not more than the target. In general, the world has come to the consensus that limiting warming to 1.5 degrees Celsius (°C) or less than 2°C can avoid some of the more dire consequences associated with projected climate change. A tremendous amount of effort has been put forth by the climate science community to estimate a bright-line budget consistent with the consensus temperature targets. The budget has evolved over time as scientists refine data and estimates of cumulative carbon emissions that have already occurred. The newest budget estimates are expressed as the remaining cumulative CO_2 emissions from the start of 2018 until the time of net zero global emissions and suggest a value between approximately 420 gigatons of carbon dioxide ($GtCO_2$) and 580 $GtCO_2$. For the purposes of this analysis, an average of 500 $GtCO_2$ is used (BLM 2019).

Over the life of the project, the Mine is anticipated to generate 300.3 million tons of CO_2e (direct and indirect) if all of the recoverable coal is mined under the Proposed Action. The federal scope or portion of that estimate would be 14.3 percent or 42.9 million tons of CO_2e (Proposed Action minus the No Action Alternative). Although not strictly a one-to-one comparison, on a CO_2e basis, the No Action Alternative would consume approximately 0.06 percent of the remaining carbon budget, while the federal scope of the Proposed Action Alternative would consume 0.01 percent.

<u>Projected Climate Change.</u> The future climate equilibrium depends on warming caused by past anthropogenic emissions, future anthropogenic emissions, and natural variability. The following information on predicted climate change has been summarized from the Intergovernmental Panel on

Climate Change (IPCC) Summary to Policymakers (IPCC 2014). It is virtually certain that there will be more frequent hot and fewer cold temperature extremes over most land areas on daily and seasonal timescales as global mean surface temperature increases. It is also very likely that heat waves will occur with a higher frequency and longer duration. Occasional cold winter extremes will continue to occur due to the inherent variability within the climate system. Changes in precipitation patterns will not be uniform, but in general, scientists expect arid regions to become dryer, while wetter areas can expect more frequent exceptional precipitation events. Oceans will continue to warm, with the greatest impacts occurring at the surface of tropical and northern hemisphere subtropical regions. All climate model projections indicate future warming in Colorado. In general, the majority of published research indicates a tendency towards future decreases in annual streamflow for all of Colorado's river basins. Increased warming, drought, and insect outbreaks, all caused by or linked to climate change, will continue to increase wildfire risks and impacts to people and ecosystems.

In 2018, the IPCC released a special report (IPCC 2018) on the impacts of global warming of 1.5°C above pre-industrial levels and summarizes their conclusions from a number of key findings, several of which are excerpted here:

- Human activities are estimated to have caused approximately 1.0°C of global warming above pre-industrial levels, with a likely range of 0.8°C to 1.2°C, and warming is likely to reach 1.5°C between 2030 and 2052 if it continues to increase at the current rate.
- Warming from anthropogenic emissions from the pre-industrial period to the present will persist for centuries to millennia and will continue to cause further long-term changes in the climate system, but these emissions alone are unlikely to cause global warming of 1.5°C (medium confidence).
- Climate models project robust differences in regional climate characteristics between present-day and global warming of 1.5°C, and between 1.5°C and 2°C. These differences include increases in mean temperature in most land and ocean regions (high confidence), hot extremes in most inhabited regions (high confidence), heavy precipitation in several regions (medium confidence), and the probability of drought and precipitation deficits in some regions (medium confidence).
- By 2100, global mean sea level rise is projected to be around 0.1 meter lower with global warming of 1.5°C compared to 2°C (medium confidence). Sea level will continue to rise well beyond 2100 (high confidence), and the magnitude and rate of this rise depend on future emission pathways. A slower rate of sea level rise enables greater opportunities for adaptation in the human and ecological systems of small islands, low-lying coastal areas, and deltas (medium confidence).
- Limiting global warming to 1.5°C compared to 2°C is projected to reduce increases in ocean temperature as well as associated increases in ocean acidity and decreases in ocean oxygen levels (high confidence), all of which will reduce risks to marine biodiversity, fisheries, and ecosystems and their functions and services to humans.

Effects on Public Health & Safety. The following data have been summarized from the Centers for Disease Control and Prevention's Climate Effects on Health assessment (CDC 2019). Climate change and other natural and human-made health stressors influence human health and disease in numerous ways. Some existing health threats will intensify, and new health threats will emerge as a result of climate change. Key weather and climate drivers of health impacts include increasingly frequent, intense, and longer-lasting extreme heat, which worsen drought, wildfire, and air pollution risks; increasingly frequent extreme precipitation, intense storms, and changes in precipitation patterns that lead to drought and ecosystem changes; and rising sea levels that intensify coastal flooding and storm surges. Key drivers of vulnerability include the attributes of certain groups (age, socioeconomic status, race, and current level of health) and of place (floodplains, coastal zones, and urban areas), as well as the resilience of critical public health infrastructure. Health effects of these disruptions include increased respiratory and cardiovascular disease, injuries, and premature deaths related to extreme weather events; changes in the prevalence and geographical distribution of foodborne and waterborne illnesses and other infectious diseases; and threats to mental health.

Social Cost of Carbon. A protocol to estimate what is referenced as the "social cost of carbon" (SCC) associated with GHG emissions was developed by a federal Interagency Working Group to assist federal agencies in assessing the costs and the benefits of proposed regulations as part of their regulatory impact analyses. The SCC is an estimate of the economic damages associated with an increase in CO_2 emissions and is intended to be used as part of a cost-benefit analysis for proposed rules. Detailed information regarding SCC is provided in **Appendix A**.

BLM does not undertake an analysis of SCC for NEPA because:

1. NEPA is not a rulemaking for which the SCC protocol was originally developed.
2. The technical supporting documents and associated guidance have been withdrawn by executive order.
3. NEPA does not require cost-benefit analysis, and this EA did not conduct an economic cost-benefit analysis.
4. The full social benefits of most NEPA actions are not monetized, and quantifying only the costs of GHG emissions but not the benefits would yield information that is both inaccurate and not useful for the decision-maker, especially given that there are no current criteria or thresholds that determine a level of significance for SCC monetary values.

Mitigation. The Proposed Action is unlikely to contribute significantly to air quality degradation in the analysis region. The area is currently in compliance with the NAAQS, and the facility will be required to update or amend existing Colorado Department of Health and Environment (CDPHE) permits to accommodate the additional coal throughput NECC is likely to seek as it resumes operations. The analysis shows that the project design features (including Air Pollution Control Division [APCD] permit required controls) are adequate to maintain compliance with the NAAQS. Likewise, the cumulative analysis of the region indicates that restarting the New Elk Mine does not contribute significantly to air quality concerns. Therefore, no additional mitigation is required for the project.

3.4 Issue 2: What Effect would Leasing and Mining the Coal from the LBA Tracts have on the Quantity and Quality of Shallow Groundwater Accessed by Residential and Agricultural Users?

3.4.1 Affected Environment

Regional groundwater flow in the basin depends largely on geologic structure and topography. The regional flow is west to east and down dip. In the New Elk permit area, the strata dip on average 2 degrees to the northeast. Based on these structural controls and topography, the groundwater flow in the permit area is west to east with a slight northern component as water discharges into the Purgatoire River (NECC 2018a).

The Colorado Geological Survey (CGS) has identified three groundwater aquifers present in the Raton Basin above the base of the Vermejo Formation. These aquifers are the Quaternary Alluvium, the Poison Canyon Aquifer, and the Raton Vermejo Aquifer. The aquifer of concern with regard to the mine workings is the Raton Vermejo Aquifer, as it underlies the other two aquifers throughout the mine area and contains the coal seams planned for mining. The CGS stated that the sandstone layers transmit water, but thick coal seams also contribute water. Transmissivities of the Raton Vermejo Aquifer range from 2 to 79 feet per day (ft/day) across the basin. During the 2010 drilling program, extensive packer testing was performed to fully identify the hydrologic characteristics of the strata and coal seams. It was determined that the coal seams were the major source of groundwater in the Raton Formation. Aside from the coal seams and fractures within sandstone bodies of the Raton Formations, other groundwater sources occur within the Quaternary Alluvium deposited in the Purgatoire River valley (NECC 2018a).

Overburden testing at the New Elk Mine did not reveal potentially acid-forming material in strata above and immediately below the coal beds. Also, mine discharge water from active and abandoned mine workings is treated on the surface and discharged to the Purgatoire River. This water can infiltrate into wetlands and shallow aquifers used downstream of the Mine. Although the discharge water is more alkaline and has a higher dissolved-solids concentration than Purgatoire River water, it is suitable for wildlife, livestock, and agricultural uses (NECC 2018a).

The water monitoring program at the New Elk Mine has collected information since the early 1980s. The program includes testing of streams, springs, shallow alluvial wells, deep bedrock wells, and mine discharge. This monitoring has established the water quality and quantity baseline from which impacts of mine operations can be evaluated. These analyses are presented in the Annual Hydrologic Monitoring Report submitted to the CDRMS (NECC 2018b). Also, the existing mine facilities currently discharge treated wastewaters into the Purgatoire River under CDPHE permit number CO0000906.

3.4.2 Environmental Impacts

3.4.2.1 Impacts of the No Action Alternative

There would be no coal produced from the LBA tracts under the No Action Alternative. However, surface water and shallow groundwater in contact with existing surface facilities and coal waste deposits would continue to be sources of waste-derived solutes. Mining would continue in the privately and state-owned coal for the remaining operational life of the mine, adding to the waste at the refuse disposal facility.

Surface water runoff from the existing surface facilities area is captured and routed to settling ponds for treatment and discharge to the Purgatoire River system. NECC monitors these ponds at the discharge points and must comply with limitations as required by the CDPHE discharge permit, which was issued to the Mine in the early 1980s. The Mine has generally complied with water quality discharge limitations; however, over the years, some exceedance of iron, pH, dissolved solids, and suspended solids have occurred. Data collected from monitoring points in 2017 are consistent with historical ranges of water quality parameters and are presented in this assessment to show changes in water quality as a result of existing disturbance and operations over the past 35 years.

At sediment Pond 007, which collects runoff water from the disturbed surface facilities area, a water quality sample from the Pond from 2017 shows total dissolved solids (TDS) at 692 milligrams per liter (mg/L), total dissolved iron at 0.07 mg/L, dissolved manganese at 0.009 mg/L, dissolved sodium at 50.8 mg/L, and sodium adsorption ratio (SAR) at 3.2 mg/L (NECC 2018b). These parameters are highlighted to show key constituents and indicators of the water quality from the disturbed area. These results are consistent with historical sampling results and show elevated concentrations over those in the Purgatoire River as described below. Results from Pond 007 whole effluent toxicity testing indicate that the water to be discharged exhibited no toxicity (NECC 2018b).

Surface water monitoring upstream and downstream of the Mine has indicated a slight increase in dissolved solids as a result of surface disturbance and discharge from the surface facilities area. Historical mine facilities in the early 1950s at the New Elk east and west portals were constructed of mine development wastes, and exposure and leaching of these uncontrolled materials have contributed to the increase in dissolved metals and dissolved solids as reported. Water quality samples from 2017 on the

Purgatoire River at sites PRS-1 above the Mine and PRS-4 below the Mine indicate TDS at 206 mg/L vs 190 mg/L, total dissolved iron at 0.02 mg/L vs 0.09 mg/L, dissolved manganese at 0.005 mg/L vs 0.025 mg/L, dissolved sodium at 6.6 mg/L vs 7.1 mg/L, and SAR at 0.24 mg/L vs 0.26 mg/L (NECC 2018b). These data are consistent over the historical monitoring period showing contributions of these constituents to the Purgatoire River system (NECC 2015).

A monitoring network of shallow and deep wells has indicated seasonal variations in water levels in aquifers directly above or in coal seams. One set of water quality samples from 2017 in the Purgatoire River alluvium at sites PAW-1 above the Mine and PAW-2 below the Mine indicate TDS at 108 mg/L vs 928 mg/L, total dissolved iron at 0.32 mg/L vs 1.06 mg/L, dissolved manganese at 0.009 mg/L vs 1.82 mg/L, dissolved sodium at 14.7 mg/L vs 139 mg/L, and SAR at 0.75 mg/L vs 2.9 mg/L (NECC 2018b). These ranges are consistent over the historical monitoring period, showing elevated concentrations of these constituents in the alluvium downstream of the Mine that seep into the Purgatoire River system.

Deep wells where historical longwall mining occurred in the Allen Seam show some drawdown of water levels in the water-bearing zones above that seam and within the coal (NECC 2018b). Recent mining in the Blue Seam has not produced any mine discharge; however, some limited quantities of seepage were observed in the mine workings. As mine workings expand over the 30-year mine plan in the Blue and Maxwell Seams, additional water seepage is anticipated and would be discharged into the Purgatoire River following appropriate treatment to meet discharge effluent limits required by the National Pollutant Discharge Elimination System (NPDES) permit.

The Purgatoire River is the water source for multiple downstream water users including agricultural irrigation, municipal water supply, and fish and wildlife habitat. Water used at the New Elk Mine for coal processing and other general uses comes from water rights held by NECC. These uses would continue as NECC mines the privately and state-owned coal under the current mine plan. The room-and-pillar method of mining proposed at the New Elk Mine would eliminate subsidence and damage to area aquifers and streams. No additional water is anticipated to be used, and there would be no depletion of water supply to downstream water users. Water quality below the Mine would be maintained for the intended downstream users with negligible impacts to agricultural, municipal, or fish and wildlife uses.

3.4.2.2 Impacts of the Proposed Action Alternative

Potential impacts from mining the coal contained in the lease areas would be similar to those associated with the No Action Alternative and would extend these impacts for an additional 5 years added to the 30-year mine plan. The extended underground mine area would produce additional seepage into the Mine that would be discharged to the Purgatoire River system. This seepage would have negligible effects on surface water or shallow groundwater resources or users because the room-and-pillar method of mining would not create subsidence and would protect upper water-bearing zones from mining damage. Water quality for downstream users would also be maintained through discharge treatment to allowable limits set by the NPDES discharge permit.

3.4.2.3 Cumulative Impacts

Cumulative impacts of mining activities on surface water, shallow groundwater, and water availability to downstream water users combined with other industrial uses and discharges (CBM development and construction/operation of the New Elk railroad) and agricultural and residential subdivision developments in the upper Purgatoire River basin would have minor effects on the quality and quantity of the water for uses such as crop irrigation, municipal water supply, and fish and wildlife habitat. Runoff from irrigation and discharges from CBM wells increase dissolved solids, dissolved metals, sedimentation, and turbidity in the receiving streams, resulting in a minor decrease of crop production rates and productivity of fish and wildlife populations as these waters are used.

3.5 Issue 3: What Effect would Leasing and Mining the Coal from the LBA Tracts and the Permanent Storage of Coal Mine Waste have on Water Quality, Terrestrial Wildlife, and Fisheries in the Nearby Purgatoire River and Wetland Areas?

The geographic scope of analysis associated with this issue is the area surrounding the Mine surface facilities, refuse disposal area, and the Purgatoire River valley within and below the Mine to Trinidad Lake near Trinidad. This area includes the Mine and areas downstream where direct, indirect, and cumulative impacts may occur.

3.5.1 Affected Environment

The proposed coal lease is located in the upper Purgatoire River valley of south-central Colorado, within Purgatoire sub-basin (hydrologic unit code [HUC]-8: 11020010) of the Headwaters Purgatoire River watershed (HUC-10: 1102001001). Water quality in this basin varies and is impacted by many activities including CBM development, coal mining, ranching, agriculture, and residential subdivision development. The general geology of the area slopes to the east with spring and seep contributions into the Purgatoire River that contain elevated dissolved solids as water flows east of the Mine to Trinidad. The majority of the Purgatoire River and its tributaries, including the Middle Fork (along which the surface facilities are located), the South Fork (which runs through the permit area on the south and east sides), and the main stem (from Weston to Trinidad Lake), is identified on the Colorado 303(d) list as being water quality impaired by total arsenic. It is also on the state Monitoring and Evaluation list for water temperature. Apache Canyon, which runs through the permit area south of the existing surface features, is on the Colorado 303(d) list for macroinvertebrate impairment. Wet Canyon and its tributaries, which run through the permit area to the north and east, are on the Monitoring and Evaluation list for temperature. Trinidad Lake on the Purgatoire River near Trinidad is also identified on the Colorado 303(d) list as being water quality impaired by total arsenic (CDPHE 2018).

Flow rates in the Purgatoire River vary widely depending on the season and interannual climate fluctuations. Based on U.S. Geologic Survey (USGS) monitoring stations both upstream and downstream of the Mine, flow levels over several years ranged from 28 to 1,640 cubic feet per second (cfs). During sampling conducted at the Mine surface facilities, historical flow rates ranged from 137 to 1,216 cfs (NECC 2018b).

In addition to the Purgatoire River and its tributaries, several wetland types are present in the Mine permit area (U.S. Fish and Wildlife Service [USFWS] 2018). These wetland types include freshwater emergent wetlands, freshwater forested/shrub wetlands, freshwater ponds, and riverine systems that provide habitat for the local flora and fauna. The Mine area includes portions of the Bosque del Oso State Wildlife Area, which provides recreational opportunities such as hunting, fishing, and hiking. Wildlife species of interest in the Mine area include elk; mule deer; turkey; and many other non-game mammals, birds, amphibians, and reptiles. The Purgatoire River provides habitat for several species of fish including trout.

Water quality impacts from the New Elk mine have had a negligible to minor effect on the Purgatoire River. The predominant source of this impact is the contribution of a saline sodium bicarbonate mine water discharge to the Purgatoire River from historical mining and dewatering of the Allen Seam. Other impacts include a minor amount of drainage from the refuse disposal area and backfilling of a short reach of the Middle Fork of the Purgatoire River with mine development waste. Water quality within the alluvium located on the Purgatoire River running through the Mine exhibits elevated concentrations of dissolved solids (chloride, bicarbonate, sodium, sulfate) and metals (manganese, iron) (NECC 2018b).

3.5.2 Environmental Impacts

3.5.2.1 Impacts of the No Action Alternative

Surface water runoff and shallow groundwater in contact with existing mine waste deposits at the New Elk surface facilities and refuse disposal area would continue to be sources of waste-derived solutes. Mining and coal processing would continue on the privately and state-owned coal for the remaining 30-year operational life of the Mine, adding to the volume of waste stored at the existing refuse disposal area and an expanded area to the east as more preparation plant and mine development wastes are produced through subsequent years of the mine plan. Water quality and slope stability monitoring is ongoing since construction of the refuse disposal area began in 1984. Shallow wells (TH-201, TH-202, and TH-203) were installed near the base of the facility to monitor accumulations of water at the refuse/bedrock interface and identify potential instability conditions of the material. Results of monitoring these wells indicate limited accumulation of water. Sediment Pond 008 was established at the base of the facility to collect any runoff from the disturbed area. Sampling results from one discharge event of the Pond during 2017 showed total dissolved iron at 0.23 mg/L, dissolved manganese at 0.006 mg/L, dissolved sodium at 63.6 mg/L, and SAR at 6.3 mg/L. If water quality is not in compliance with discharge limitations, the water is pumped to other ponds at the Mine surface facilities area, treated, and discharged when standards are met (NECC 2018b). Infiltration and seepage of elevated concentration waters from the refuse disposal area to the Purgatoire River would have minor impacts on area water quality.

Water quality monitoring of the Purgatoire River has identified several reaches as impaired from several pollutants as described above. Ongoing mining operation activities, future disturbance of habitat, and contributions of discharged water would have minor effects on fisheries and terrestrial wildlife populations in the New Elk Mine area. This would include degradation of habitat that could limit productivity and use by both aquatic and terrestrial species. This limitation could decrease the quality of recreational opportunities in the area.

3.5.2.2 Impacts of the Proposed Action Alternative

Potential impacts from mining the coal contained in the lease areas and storage of preparation plant and mine development wastes at the refuse disposal area would be similar to those associated with the No Action Alternative and would extend these impacts for an additional 5 years added to the 30-year mine plan. Of the 8 million tons of coal mined from the lease areas, approximately 3 million tons would be preparation plant and mine development wastes and deposited in the refuse disposal area. This quantity of material would occupy a portion of the expanded disposal area and contribute to land disturbance and potential for water seepage and discharge. The disturbance would change land uses and contribute to fragmentation of wildlife habitat. Water from the disturbed area would be captured and treated, but discharges or infiltration would have minor to negligible effects on surface water or shallow groundwater resources or users. These impacts would have minor direct and indirect effects on fishery and wildlife populations in the area. Water quality for downstream users would also be maintained through discharge treatment to allowable limits set by the NPDES discharge permit.

3.5.2.3 Cumulative Impacts

Cumulative impacts of mine water discharge and seepage and expanded mine activities and expansion combined with other industrial discharges (CBM development and construction/operation of the New Elk railroad) and runoff from agricultural and residential subdivision developments in the Purgatoire River valley would have minor effects on the quality of the water for uses such as crop irrigation and fish and wildlife habitat. Increases in dissolved solids, metals, and turbidity would decrease crop production rates and productivity of fish and wildlife populations depending on the resulting water quality. As development trends increase in the area (such as with CBM development) this would result in minor changes in land uses and fragmentation of wildlife habitats, causing changes in wildlife use and populations.

3.6 Issue 4: How would the Truck and Train Transportation of Coal Leased from the LBA Tracts Affect Traffic, Accidents, Noise, Road Conditions, and Wildlife Populations

Transportation of the mined coal from the New Elk Mine would be trucked on State Highway 12 to the Jansen Railroad Loadout in Trinidad, Colorado. This method would continue until production of the mine reaches approximately 1 million tons of coal per year. Depending on the signed coal contracts, this may be as soon as year 3 after mining resumes. At that time, the railroad tracks from Jansen Railroad Loadout to the New Elk Mine would be reinstalled on the existing railroad bed. Construction of the railroad does not require any federal approvals, as it will be privately owned and operated. Potential impacts of coal transportation from Jansen Railroad Loadout to the point of use are described for air/climate in Issue 1 of this section. These plans are independent of approval or denial of the LBA.

3.6.1 Affected Environment

State Highway 12 from the New Elk Mine to the Jansen Railroad Loadout is a two-lane asphalt road that would act as the sole truck transport route from the Mine site. State Highway 12 sees local and industrial traffic. It is also a part of the Colorado scenic byway system and, as a result, the highway supports recreational traffic for sight-seeing, hunting, and other activities. The road has a speed limit that ranges between 60 mile per hour (mph) near the existing Mine surface facilities to 25 mph near the Town of Trinidad. In 2016, when the Mine was inactive, the annual average daily traffic on State Highway 12 ranged from 600 near the Mine to 9,000 near the Town of Trinidad. The traffic near the Mine had a higher proportion of truck travel (up to 9.4 percent) than near the Town of Trinidad (as low as 3.3 percent). Traffic counts were similar in 2013 when the Mine was active; however, the percentage of truck travel was higher (14 percent near the Mine and 9 percent near Trinidad). The maximum average volume to capacity ratio was 0.46 near the Town of Trinidad (Colorado Department of Transportation [CDOT] 2018).

A railroad line to the New Elk Mine was built in the early 1950s. Because of closure of the New Elk and Golden Eagle Mines, the rails and ties were decommissioned and removed in 2009. However, the grade bed remains intact.

3.6.2 Environmental Impacts

3.6.2.1 Impacts of the No Action Alternative

Under the No Action Alternative, the LBA tracts would not be mined or contribute to traffic on State Highway 12. NECC would continue mining on the privately and state-owned coal tracts for the operational life of the mine and use the highway and railroad to move coal to the intended markets. Animas County recorded 343 traffic accidents in 2017, and the increase in Mine-related traffic could increase the number of accidents. If production does not meet the necessary capacity for railroad reinstallation, at a maximum production of 1 million tpy and an average payload of 23 tons per truck, traffic volume would be up to 167 trucks per weekday in each direction.

At full production, the Mine would create 175 employee round trips per weekday, and other suppliers and contractors would create 50 round trips per weekday. These combined round trips (392 per weekday) represent an approximately 65 percent increase in traffic volume from 2016 levels near the Mine but only a 4 percent increase in traffic levels near the Town of Trinidad. These traffic increases in the area of the Mine would cause congestion and the possibility of accidents for the local residents, more so during shift changes at the Mine. If between 1 and 2 million tons of coal are mined annually, production would be sufficient for railroad reinstallation. In this case, assuming an average train length of 120 cars with a capacity of 120 tons per car, there would be between 1.3 and 2.7 round-trip train transits per week. Demand for highway transportation infrastructure for employees and services for the mining operations would remain the same as before railroad installation. Maintenance of State Highway 12 would continue to be provided by the CDOT.

Mine-associated truck and auto traffic on State Highway 12 would create noise, congestion with increased human activity, and the potential for transportation accidents. Noise would affect quality of life in properties and the local communities of Weston, Segundo, Valdez, Cokedale, Jansen, and western Trinidad along the Highway, and property values could be affected. Heavy truck noise is approximately 80 to 85 decibels, while normal community noise at 45 to 55 decibels. The elevated truck noise would be short term, but there would be numerous trips during the hauling period every day. This could also lead to minor local changes in wildlife habitat use, the distribution of wildlife populations, and vehicle collisions with increased road traffic. The quality of recreation opportunities in the area (including the State Wildlife Area) could also be affected by these minor changes of less desirable habitat near the Highway and distribution of wildlife populations further from the highway and Mine area. Increased human presence in the area could also lead to illegal taking of wildlife.

As coal production at the Mine increases above 1 million tpy, the railroad from the Mine to the Jansen Railroad Loadout in Trinidad would be installed. This would eliminate coal truck traffic on State Highway 12, reducing congestion and the possibility of auto or wildlife accidents with those trucks. Railroad noise would increase in rural communities and could affect wildlife habitat occupation along the areas through which it passes. There is also the potential for wildlife-train collisions along the route.

3.6.2.2 Impacts of the Proposed Action Alternative

Mining of the LBA tracts would not change the annual rate of production of the Mine or the amount of coal hauled by truck or rail to the Jansen Railroad Loadout. Traffic associated with mining operations would be similar to that associated with the No Action Alternative. The Proposed Action would, however, add 5 additional years of the annual traffic resulting from hauling coal.

The additional projected lifespan of the Mine under the Proposed Action does not require reinstallation of the decommissioned railroad line. Annual production of the Mine would need to reach 1 million tons for the railroad to be economically feasible. Depending on coal contracts, production could reach 1 million tons per year within the first 3 years after mining resumes. In this case, traffic to and from the Mine would still be elevated from current levels due to commuters and deliveries, but little or no heavy truck traffic would be expected on State Highway 12.

3.6.2.3 Cumulative Impacts

Cumulative impacts of long-term traffic on State Highway 12 to the Mine over the 35-year mine plan with other area activities including CBM development, residential subdivisions, agriculture, and recreation activities would add to congestion on the highway, reduced speeds because of traffic volume, and potential for auto and wildlife accidents. Construction/operation of the New Elk railroad at higher coal production levels would reduce State Highway 12 truck traffic.

3.7 Issue 5: How would Leasing and Mining of Coal from the LBA Tracts Affect the Socioeconomic Conditions in the Mine Area?

The scope of analysis includes how leasing and mining the LBA tracts would affect the socioeconomic conditions in the Mine area. Approving the LBA would allow for a 5-year continuation of metallurgical coal mining at the New Elk Mine.

3.7.1 Affected Environment

The social and economic analysis area includes Las Animas County, including the City of Trinidad and small communities in the Purgatoire River Valley near the Mine. Many residents of the county depend on resource-based employment for their livelihood and lifestyle, such as agriculture, ranching, logging, oil and gas, and mining. Coal mining has historically been part of the county economy for nearly 100 years. During the early to mid-1900s, there were numerous surface and underground coal mines in the Purgatoire River valley employing hundreds of people at the mines and supporting industries. As economics dictated, the smaller mines closed, and by the early 1980s/1990s, only the New Elk, Golden Eagle, and Lorencito Canyon Mines were operating. Today, only the New Elk Mine has an active CDRMS permit and is currently idle while the Lorencito Canyon Mine is in reclamation and the CDRMS permit status is Permanent Cessation. This rural area is affected by employment levels at the Mine, whether by direct employment (175 employees at full production) or other Mine-related businesses and services.

According to 2017 estimates, Las Animas County is home to 14,238 residents, an average of 3.2 people per square mile (U.S. Census Bureau 2018). It is estimated that the population of the county has dropped by 8.2 percent since 2010.

Las Animas County is less affluent than other parts of the Colorado Front Range, but modestly more affluent than the surrounding counties in southeastern Colorado, which are among the poorest in the state. Between 2012 and 2016, the median household income was $42,808, and the median home value was $145,800. As of 2016, it was estimated that 21.6 percent of persons in the county lived below the poverty line, and total employment in the county was 3,122 jobs. Between 2012 and 2016, 56.8 percent of the population aged 16 or older was in the workforce (U.S. Census Bureau 2018).

The Blue and Maxwell Seams to be mined are classified as metallurgical-grade coals best targeted for use in the production of steel from iron ore. NECC potential met-coal markets include China, Korea, Japan, and Brazil, but the location of coal use would depend on a signed coal contract. NECC currently anticipates mining more than 73 million recoverable tons of coal reserves currently privately and state-owned and leased by NECC. The estimated recoverable federal coal reserves in the LBA total 8 million tons and can be accessed with the current mine plan, as a permit revision is approved by CDRMS. Acquisition of the BLM lease increases recoverable reserves by approximately 11 percent, provides better access to some of the existing reserves by complete mining in the block of reserves, and extends projected mining by 5 years to a 35-year life of mine. NECC has other reserves under lease that could be incorporated into the mine plan to maintain the 30-year life of mine if the LBA was denied.

3.7.2 Environmental Impacts

3.7.2.1 Impacts of the No Action Alternative

NECC would not mine the coal contained within the LBA tracts. Approximately 8 million tons of recoverable federal coal deposits would be bypassed and likely not developed in the foreseeable future due to the following constraints: 1) depth of coal, 2) limited acreage (1,279 acres split into three tracts), 3) quantity of recoverable coal, and 4) difficulty of future mine access (directly adjacent privately and state-owned coal reserves controlled by NECC). Bypassing the LBA would render these federal tracts operationally and geologically isolated. Any future attempt at recovery of these federal coal deposits would be challenging from an operational perspective. In particular, proper ventilation and access shafts on these small tracts would be cost-prohibitive for the amount of coal to be recovered. Ultimately, 8 million tons of federal coal would not be available for industrial uses and revenues from the lease would be lost. For the remaining operational life of the Mine, NECC would continue to contribute to annual coal production. Additionally, the reasonably foreseeable future development of coal reserves in the New Elk vicinity would still be expected.

The New Elk Mine is permitted by the CDRMS, and the operations status is active; however, there is no current coal production due to no existing coal purchase contracts. As NECC obtains coal purchase contracts, mining would begin and employees would be hired to increase to full production of 2.0 million tpy as necessary. At this production level, employment at the Mine would be approximately 175 jobs. There are now seven employees at the Mine, as it is currently idle. Average wages for full-time permanent employees are approximately $80,000 per year (NECC 2018c). It is anticipated that jobs would be filled primarily from the Trinidad area; however, some employment would come from other areas in or outside of the county. Other support jobs may be created as mining begins and facility upgrade projects are constructed, such as replacing the railroad tracks from the Mine to Jansen Railroad Loadout. It is anticipated that the existing labor force in the area would be sufficient to provide employees for the Mine, and housing would be available for those that may move to the area for mining jobs. Other supporting infrastructure, such as schools, hospitals, and other services, would also be sufficient to accommodate families that would relocate to the area. Leasing the LBA coal would not affect the strategy or timing for local employment, as the Mine would continue mining operations as coal contracts are secured.

The New Elk Mine would provide local tax revenue consisting of Real Estate and Personal Property Tax to Las Animas County for the related life of mine period. As mining begins, these taxes would increase from current 2017 levels as more equipment is purchased. As time progresses and coal production increases, tax revenue should level out approximately as shown for the 2012-2013 levels when the Mine was active. Tax revenue provided to the County for the past 7 years is as follows (NECC 2018c):

2011: $224,884	2012: $269,310	2013: $304,801
2014: $252,228	2015: $196,300	2016: $226,473
2017: $171,734		

Additional tax revenue for the county would also be available from supporting businesses and facilities upgrades planned for the Mine.

3.7.2.2 Impacts of the Proposed Action Alternative

The issuance of the lease adds reserves to the existing mining operation and would have minor impact on the existing social or infrastructure systems of local communities. The leased coal would extend the life of the Mine by 5 years, and coal would continue to be provided to industrial markets. Employment, tax revenue, and stimulation to the local economy would continue during this period. Local tax items consist of real estate and personal property tax to Las Animas County from the existing operations have averaged $250,000 per year over the past 7 years and would increase as mining begins and increases to full production (NECC 2018c). NECC would also pay royalties on the 8 million tons of federal coal mined from the lease.

3.7.2.3 Cumulative Impacts

Cumulative effects of leasing the coal would extend coal mining at the New Elk Mine by 5 years to a 35-year life of mine plan. Mining activities along with other industrial activities (such as CBM development and construction/operation of the New Elk railroad), agriculture, residential subdivision development, and recreational activities would continue to sustain the local economy over this period. However, mining could degrade the quality of life of this rural area by increased population and human activity, highway congestion, and historical land uses. Increases in cumulative development would result in changes to the quality of life, changes in land uses from rural agriculture/ranching to industrial or residential, and fragmentation of wildlife habitats causing changes in wildlife use and populations.

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CHAPTER 4 COORDINATION, CONSULTATION, AND LIST OF PREPARERS

4.1 Cooperating Agency Involvement

The OSMRE and the CDNR are Cooperating Agencies on this project because they have special expertise in coal mining and associated environmental effects. Although the CDRMS, through a cooperative agreement with the Secretary of the Interior, is the coal mining regulatory authority for federal lands (leased federal coal) in Colorado, OSMRE has oversight responsibility for the Colorado coal program. If the lease is issued, OSMRE would determine if there is a need for a federal mining plan modification at the time the actual state permitting process is underway with CDRMS. If a federal mining plan modification is needed, the OSMRE would be responsible for preparing a mine plan decision document (MPDD) recommending that the Deputy Assistant Secretary of the Interior, Land and Minerals Management approve, approve with conditions, or not approve the mining plan modification under 30 CFR 746. A permit revision application to the existing permit for the New Elk Mine would be required for CDRMS to incorporate and approve the new mine plans and lands associated with the lease areas.

4.2 Tribal Consultation

A consultation with potentially interested Native American tribes commenced on August 30, 2018 [CR-RG-18-114 NA]. The BLM contacted the following tribes: Apache Tribe of Oklahoma, Cheyenne and Arapaho Tribes of Oklahoma, Cheyenne River Sioux Tribe, Comanche Tribe of Oklahoma, Crow Creek Sioux, Eastern Shoshone, Jicarilla Apache Nation, Kiowa Tribe of Oklahoma, Northern Arapaho Tribe, Northern Cheyenne Tribe, the Ute Tribe, Oglala Sioux Tribe, Rosebud Sioux Tribe, Southern Ute Tribe, Standing Rock Lakota Tribe, and the Ute Mountain Ute Tribe.

BLM heard from five tribes; however, no specific concerns were identified. As a result, no further actions will be taken at present. If the tribes provide additional information in the future, BLM will work with them to address the issues.

4.3 Section 7 Consultation under the Endangered Species Act

The BLM determined that, because the coal extraction is underground and no new surface disturbance is proposed, the project would have no potential to cause impacts to threatened or endangered species in the Mine area. As the location for combustion (coking) the coal has not been determined, no impact can be determined. Therefore, the BLM has no further obligation under Section 7 of the Endangered Species Act.

4.4 List of Preparers

The following BLM, Cooperating Agencies, and Arcadis staff participated in the preparation of this EA.

Table 4-1 BLM RGFO Preparers

Subject Matter Expert	Specialty
Melissa Smeins	BLM Project Manager
Matt Rustand	Wildlife, Threatened and Endangered Species
Aaron Richter	Weeds
Negussie Tedela	Hydrology/Soils

Table 4-1 BLM RGFO Preparers

Subject Matter Expert	Specialty
Monica Weimer	Archaeology and Tribal Concerns
John Lamman	Range
Linda Skinner	Recreation
Jessica Montag	Socioeconomics
Chad Meister	Air Quality
Glenda Torres	Fuels
Jeremiah Moore	Forestry
Martin Weimer	Rocky Mountain District NEPA Coordinator

Table 4-2 Cooperating Agency Preparers

Subject Matter Expert	Specialty
Gretchen Pinkham	OSMRE
Jason Musick	CDRMS
Rob Zuber	CDRMS
Karen Voltura	CPW

Table 4-3 Arcadis Preparers

Subject Matter Expert	Specialty
Jerry Koblitz	Senior Project Manager/NEPA Advisor, Water Quality and Quantity
Eric Cowan	Project Manager
Jocelyn Finch	Ecological Resources/Project Support
Roger Felty	Air Resources
Kathryn Cloutier	Land Use, Socioeconomics, Environmental Justice, Transportation, Recreation, Visual Resources
Carl Späth	Cultural Resources
Jie Chen	GIS/Mapping
Joe Statwick	Ecologist
Carrie Womack	Document Control/Support

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APPENDIX A

AIR AND CLIMATE RESOURCES TECHNICAL REPORT

New Elk Coal Company

AIR AND CLIMATE RESOURCES TECHNICAL REPORT

New Elk Mine

April 2019

CONTENTS

TABLES

FIGURES

ACRONYMS AND ABBREVIATIONS

˚C	degrees Celsius
˚F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter of air
acfm	actual cubic feet per minute
AEO	Annual Energy Outlook
amsl	above mean sea level
APCD	Air Pollution Control Division
APEN	Air Pollutant Emission Notice
AQRV	Air Quality Related Values
AR5	IPCC Fifth Assessment Report
bbls	barrels [of oil]
BLM	U.S. Bureau of Land Management
CAA	Clean Air Act
CARMMS	Colorado Air Resources Management Modeling Study
CB	Carbon Budget
CCR	Colorado Code of Regulations
CDC	Centers for Disease Control
CDPHE	Colorado Department of Public Health and Environment
CDR	Carbon Dioxide Removal
CDRMS	Colorado Division of Mine Reclamation and Safety
CFC	chlorofluorocarbon
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CH_4	methane
CI	compression ignition
CMM	coal mine methane
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
COA	Condition of Approval
COPD	chronic obstructive pulmonary disease
CSU	Controlled Surface Use

DAT	data analysis threshold
dv	deciviews
DWDA	Development Waste Disposal Area
EA	Environmental Assessment
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EO	Executive Order
FLAG	FLM Air Quality Related Values Work Group guidance
FLM	Federal Land Manager
FLPMA	Federal Land Policy and Management Act of 1976
GHG	Greenhouse Gas
$GtCO_2$	gigatons of carbon dioxide
$GtCO_2e$	gigatons of carbon dioxide equivalent
GWP	global warming potential
HAP	hazardous air pollutant
HCFC	hydrochlorofluorocarbon
hp	horsepower
ICE	internal combustion engine
IEM	Iowa Environmental Mesonet
IMN	Insurance Marine News
IPCC	Intergovernmental Panel on Climate Change
IWG	Interagency Working Group
IWGSCC	Interagency Working Group on Social Cost of Carbon
kgN/ha-yr	kilograms nitrogen per hectare per year
km	kilometer
kW	kilowatt
lbs/hr	pounds per hour
LCA	Life Cycle Assessment
LUC	Land Use Change
m	meter
Mcf	thousand cubic feet
mg/m^3	milligrams per cubic meter

MMT	million metric tons
MOVES 2014b	Motor Vehicle Emission Simulator 2014b
mph	miles per hour
MSHA	Mine Safety and Health Administration
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NCA	U.S. National Climate Assessment
NECC	New Elk Coal Company
NEI	National Emissions Inventory
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NPS	National Park Service
NSO	No Surface Occupancy
NSPS	New Source Performance Standards
O_3	ozone
OMB	Office of Management and Budget
ONRR	Office of Natural Resources Revenue
Pb	lead
PgC	petagrams of carbon
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
RCP	Representative Concentration Pathway
RF	radiative forcing
RfC	reference concentration
RFD	Reasonably Foreseeable Development

RGFO	Royal Gorge Field Office
RMP	Resource Management Plan
RSL	Regional Screening Level
RSV	Respiratory Syncytial Virus
SCC	social cost of carbon
SI	spark ignition
SIP	State Implementation Plan
SO_2	sulfur dioxide
SVR	standard visual range
Tg yr–1	teragrams per year
TL	Timing Limitations
tpy	tons per year
TSP	total suspended particulate
USCB	U.S. Census Bureau
USDA	U.S. Department of Agriculture
USEPA	U.S. Environmental Protection Agency
USFS	U.S. Forest Service
VOC	volatile organic compound
WRCC	Western Regional Climate Center
WRI	World Resources Institute

1 AIR AND CLIMATE RESOURCES

1.1 Affected Environment

1.1.1 Analysis Area

Air quality for any region is influenced by the amount of pollutants released within the vicinity and upwind of the region and can be highly dependent on the contaminants' chemical and physical properties. Additionally, an area's topography or terrain (mountains and valleys) and weather, such as wind speed and direction, temperature, air pressure (the resulting turbulence), rainfall, and cloud cover, can all have a direct influence on how pollutants accumulate, form, or disperse in the local environment. Transportation is another important consideration, as some pollutants can be transported far from their origins (e.g., ozone, secondary particulate matter smaller than 2.5 microns [$PM_{2.5}$], mercury).

The affected environment for the air quality analysis of direct effects in association with the New Elk Mine (the Mine) includes the western portions of Las Animas County, Colorado, although most direct air quality impacts would be limited to the vicinity of the mine itself. Indirect effects associated with coal transport and combustion would occur at numerous locations. All of the coal produced at the New Elk Mine is marketed for export to international steel manufacturers for use as metallurgical coal. Saleable coal would be initially transported by truck to Jansen Rail Yard, where it would then be taken to an international shipping port and shipped overseas (assumption for analysis because New Elk Coal Company [NECC] does not have any current customer contracts).

1.1.1.1 Regional Climate

The project area is located in a semiarid (dry and cold), mid-continental climate regime. The area is typified by dry, sunny days; clear nights; and wide daily temperature variations. The nearest long-term meteorological station with both historical and recent data is at Trinidad, Colorado (1948-2008), located approximately 25 miles east of the project area at an elevation of 6,030 feet above mean sea level (amsl) (Western Regional Climate Center [WRCC] 2019).

The annual average total precipitation in Trinidad is 15.55 inches, with annual recorded totals ranging from 8.69 inches (1956) to 24.68 inches (1981). Precipitation increases in the late summer, with average monthly precipitation ranging from 0.46 inch (January) to 2.47 inches (July). An average of 50.8 inches of snow falls during the year (annual high 104 inches in 1997), with the majority of the snow distributed between November and April. March is the peak snowfall month, averaging 9.6 inches.

The region has cool temperatures, with the average temperature (in degrees Fahrenheit [˚F]) ranging between 18.9˚F and 48.5˚F in January to between 57.3˚F and 86.8˚F in July. Extreme temperatures have ranged from -32˚F (1963) to 101˚F (1994, 2005). The frost-free period generally occurs from April to October. **Table 1** shows the mean monthly temperature ranges and total precipitation amounts.

Table 1 Monthly Temperature Ranges and Total Precipitation Amounts

Month	Average Temperature Range (˚F)	Total Precipitation (inches)
January	18.9–48.5	0.46
February	21.6–51.1	0.64
March	27.3–56.9	1.03
April	34.8–64.9	1.49
May	43.7–73.5	1.88
June	52.5–83.1	1.57
July	57.3–86.8	2.47
August	55.9–84.7	2.29
September	48.8–79.1	1.27
October	37.8–69.3	1.11
November	27.0–56.8	0.75
December	20.1–49.0	0.60
Mean Annual	**37.1–67.0**	**15.55**

Source: WRCC 2019

The closest comprehensive wind measurements were collected at the Trinidad/Las Animas County airport, located approximately 35 miles east-northeast of the project area. Although local wind patterns in mountainous areas are almost always controlled by local topography, those recorded at the Trinidad/Las Animas County airport, located at 5,760 feet amsl, are generally representative of typical wind patterns in the region. A windrose for the site, for years 1972 through May 2018, is presented on **Figure 1**. **Table 2** and **Table 3** provide the wind direction distribution and wind speed distribution in a tabular format. From this information, it is evident that winds originate from the west-northwest to west-southwest nearly 39% of the time. The annual mean wind speed at the Trinidad/Las Animas County airport site is 9.7 miles per hour (mph).

Table 2 Wind Direction Frequency Distribution - Trinidad/Las Animas County, Colorado, 1972 to 2018

Wind Direction	Frequency (percent)
Calm	7.1
N	5.7
NNE	3.7
NE	3.6
ENE	3.7
E	5.6
ESE	3.4
SE	2.8

Table 2 Wind Direction Frequency Distribution - Trinidad/Las Animas County, Colorado, 1972 to 2018

Wind Direction	Frequency (percent)
SSE	2.7
S	4.8
SSW	3.3
SW	5.1
WSW	13.9
W	17.2
WNW	7.7
NW	5.4
NNW	4.2

Source: Iowa Environmental Mesonet (IEM) 2018

Table 3 Wind Speed Distribution - Trinidad/Las Animas County, Colorado, 1972 to 2018

Wind Speed (mph)	Frequency (percent)
< 2.0 (Calm)	7.1
2–5	10.7
5–7	19.9
7–10	20.3
10–15	28.6
15–20	8.1
Greater than 20	5.4

Source: IEM 2018

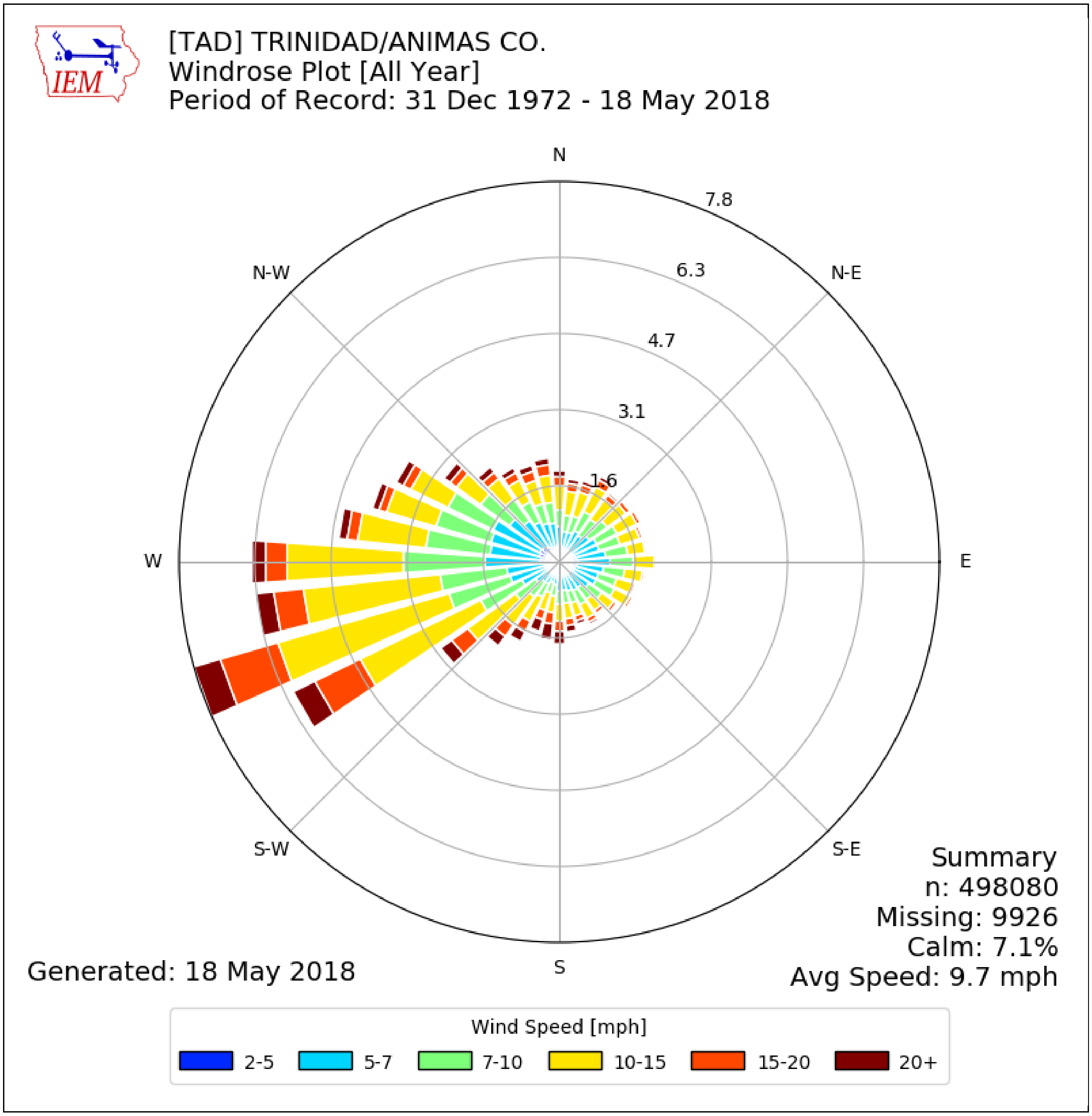

Figure 1 **Trinidad, Las Animas County Colorado Meteorological Data Wind Rose, 1972-2018**
Source: IEM 2018

1.1.1.2 Regulatory Requirements

The Clean Air Act (CAA) and the Federal Land Policy and Management Act of 1976 (FLPMA) require Bureau of Land Management (BLM) to ensure that actions taken by the agency comply with federal, state, tribal, and local air quality standards and regulations. FLPMA further directs the Secretary of the Interior to take any action necessary to prevent unnecessary or undue degradation of the lands (Section 302 [b]), and to manage the public lands "in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values" (Section 102 [a][8]).

Actions that involve federal mineral estate are also required to comply with BLM land use stipulations (federal surface only) and permit specific Conditions of Approval (COAs) that would be determined by analysis at the time of permitting/authorization. The BLM makes land use allocations and stipulation decisions during Resource Management Plan (RMP) development. There are three typical stipulation types for lands that are designated as available for future oil, gas, and coal exploration and development. They include No Surface Occupancy (NSO), Controlled Surface Use (CSU), and Timing Limitations (TLs). BLM may attach COAs to permits authorizing such activities as necessary to mitigate any potentially significant impacted resources regardless of surface ownership status. The term COA refers to a site-specific requirement included in an approved permit or sundry notice that may limit or amend the specific actions proposed by the operator to minimize, mitigate, or prevent impacts to public lands or other resources. Both stipulations and COAs are subject to enforcement by the BLM. For this action, only the COAs would apply because the Mine does not affect or occupy any federal surface estate.

The regulatory framework for air quality includes both federal and state rules, regulations, and standards promulgated by the U.S. Environmental Protection Agency (USEPA) and implemented by the Colorado Department of Public Health and Environment (CDPHE). The USEPA has established National Ambient Air Quality Standards (NAAQS) for seven criteria air pollutants, which include carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O_3), particulate matter emissions less than 10 microns or 2.5 microns in diameter (PM_{10} and $PM_{2.5}$, respectively), sulfur dioxide (SO_2), and lead (Pb). These standards are provided in **Table 4**. The Colorado Air Pollution Control Commission, by means of an approved State Implementation Plan (SIP), can establish state ambient air quality standards for a criteria pollutant that are at least as stringent as, or more so, than the NAAQS. Exposure to air pollutant concentrations greater than the NAAQS has been shown to have a detrimental impact on human health and the environment; thus, ambient air quality standards must not be violated in areas where the public has access.

Table 4 National Ambient Air Quality Standards

Pollutant	Primary/ Secondary	Averaging Time	National Standard	Form
Carbon Monoxide (CO)	Primary	8-hour	9 ppm	Not to be exceeded more than once a year
		1-hour	35 ppm	
Lead	Primary and secondary	Rolling 3-month average	0.15 µg/m^3	Not to be exceeded
Nitrogen Dioxide (NO_2)	Primary	1-hour	100 ppb	98th percentile of 1-hour daily maximum concentration, averaged over 3 years
	Primary and secondary	Annual	53 ppb	Annual Mean

Table 4 National Ambient Air Quality Standards

Pollutant		Primary/ Secondary	Averaging Time	National Standard	Form
Ozone		Primary and secondary	8-hour	0.070 ppm	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years
Particle Pollution	$PM_{2.5}$	Primary	Annual	12.0 μg/m^3	Annual mean, averaged over 3 years
		Secondary	Annual	15.0 μg/m^3	Annual mean, averaged over 3 years
		Primary and Secondary	24-hour	35 μg/m^3	98th percentile, averaged over 3 years
	PM_{10}	Primary and secondary	24-hour	150 μg/m^3	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide (SO_2)		Primary	1-hour	75 ppb	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		Secondary	3-hour	0.5 ppm	Not to be exceeded more than once per year
		n/a	3-hour*	700 μg/m^3	Not to be exceeded more than once in any twelve-month period

Notes:
* State standard established by the Colorado Air Quality Control Commission
μg/m^3 = micrograms per cubic meter of air
ppm = parts per million, ppb = parts per billion
Source: USEPA 2019

All of the criteria pollutants are directly emitted from a variety of source types, except for O_3 and $PM_{2.5}$. O_3 is chemically formed in the atmosphere via interactions 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 O_3 precursors). Secondary $PM_{2.5}$ forms when certain products of combustion (SO_2 and NO_X) cool sufficiently to condense and form a solid or aerosol that can then be measured via traditional monitoring methods.

Areas where pollutant concentrations are below the standard are considered to be in attainment with the NAAQS. Areas currently designated as nonattainment violate a standard. Two additional subset categories of attainment exist for those areas where a formal designation has not been made (i.e., Attainment/Unclassifiable [generally rural or natural areas where no monitoring data exists]) and for areas where previous violations of the NAAQS have been documented, but the pollutant concentration(s) no longer exceeds the NAAQS design value(s) (i.e., Attainment/Maintenance areas).

Compliance with the NAAQS is demonstrated by monitoring for ground level atmospheric air pollutant concentrations. CDPHE monitors ambient air quality at a number of locations throughout the state and summarizes the data in an annual report prepared to inform the public about air quality trends. The state has been divided into eight air quality regions designed to accurately reflect local air quality conditions. The Mine airshed analysis area lies in the South-Central Air Pollution Control Region. The South-Central region comprises Pueblo, Huerfano, Las Animas, and Custer Counties. Its population is approximately 192,249 (United States Census Bureau [USCB] 2019). Population centers include Pueblo, Trinidad, and Walsenburg. The region has rolling semiarid plains to the east and is mountainous to the west. All of the area complies with federal air quality standards (USEPA 2018a). In the past, the Air Pollution Control Division (APCD) has monitored particulates in both Walsenburg and Trinidad, but that monitoring was discontinued in 1979 and 1985, respectively, due to low concentrations. During 2017, there were two particulate monitors (one PM_{10} monitor and one $PM_{2.5}$ monitor) operated in the South-Central Region, both at a site located in the City of Pueblo.

1.1.1.3 Hazardous Air Pollutants

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. CAA Sections 111 and 112 establish mechanisms for controlling HAPs from stationary sources, and the USEPA is required to control emissions of 187 HAPs. Ambient air quality standards do not exist for HAPs; however, mass-based emissions limits and risk-based exposure thresholds have been established as significance criteria to require maximum achievable control technologies under the USEPA promulgated National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for 96 industrial source classes.

Many HAPs originate from stationary sources (e.g., factories, refineries, power plants) and mobile sources (e.g., cars, trucks, buses), as well as indoor sources (building materials and cleaning solvents). Most HAPs emitted from the Mine would be the result of on- and off-road vehicle use. The largest components of the HAPs emissions from these sources are typically various benzene compounds and formaldehyde.

1.1.1.4 Prevention of Significant Deterioration

All geographical regions are assigned a priority Class (either I, II, or III), which describes how much degradation to existing air quality is allowed to occur within the area under the Prevention of Significant Deterioration (PSD) permitting rules. Class I areas are areas of special national or regional natural, scenic, recreational, or historic value, and 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 the U.S.

Although the PSD rule only applies to major stationary sources of air pollution, a PSD increment analysis can provide a useful measure for estimating how likely a new source of pollution would contribute to impacts on regional air quality. A PSD increment is the amount of pollution allowed to increase in an area while preventing air quality in the airshed from deteriorating to the level set by the NAAQS. The NAAQS is a maximum allowable concentration ceiling, while a PSD increment is the maximum allowable increase in concentration allowed to occur above a baseline concentration for a pollutant within the PSD area boundary. These maximum allowable increases are shown in **Table 5**. The baseline concentration for a pollutant is defined as the ambient concentration existing at the time at which the first complete PSD permit application affecting the boundary is submitted. PSD applicable sources are required to provide an analysis to ensure that their emissions, in conjunction with other applicable emissions increases and decreases within an area, will not cause or contribute to a violation of any applicable NAAQS or PSD increment. Significant deterioration occurs when the amount of new pollution would exceed the applicable PSD increment. A regulatory PSD increment analysis is the sole responsibility of the APCD;

any subsequent analysis performed for National Environmental Policy Act (NEPA) purposes will be used for informational purposes only. The New Elk Mine is classified under the CAA as a minor source for PSD purposes because its emissions do not exceed the applicable thresholds.

Table 5 Federal Prevention of Significant Deterioration Limits

Pollutant	Averaging Time	Maximum Allowable Increase (μg/m^3)		
		Class I Area	Class II Area	Class III Area
$PM_{2.5}$	Annual	1	4	8
	24-hour	2	9	18
PM_{10}	Annual	4	17	34
	24-hour	8	30	60
SO_2	Annual	2	20	40
	24-hour	5	91	182
	3-hour	25	512	700
NO_2	Annual	2.5	25	50

Notes:
μg/m^3 = Micrograms Per Cubic Meter of Air

1.2 Air Quality Related Values

In addition to the NAAQS modeling required for PSD permitting, the PSD program includes requirements for the assessment of a source's air pollution impacts to surface waters, soils, vegetation (i.e., deposition, O_3), and visibility. These metrics are commonly referred to as Air Quality Related Values (AQRVs). Measuring and assessing potential impacts to AQRVs is particularly important at federally mandated Class I lands, which include areas such as national parks, national wilderness areas, and national monuments. Class I areas are granted special air quality protections under Section 162(a) of the CAA and the Federal Land Manager (FLM) for any such area is responsible for reviewing PSD actions to ensure that their goals for undue degradation to the resources are not impeded.

Atmospheric deposition is the process of removing pollutants from the atmosphere via mechanical and chemical processes. When air pollutants, such as sulfur and nitrogen, are deposited into ecosystems, they may cause acidification or enrichment of soils and surface waters. Atmospheric nitrogen and sulfur deposition may affect water chemistry, resulting in impacts to aquatic vegetation, invertebrate communities, amphibians, and fish. Deposition can also cause chemical changes in soils that alter soil microorganisms, plants, and trees. Although nitrogen is an essential plant nutrient, excess nitrogen from atmospheric deposition can stress ecosystems by favoring some plant species and inhibiting the growth of others. The FLMs use a deposition data analysis threshold (DAT) of 0.005 kilogram per hectare-year (kg/ha-yr) to determine the potential significance of any given project in the western U.S. as defined under the FLM Air Quality Related Values Work Group guidance (FLAG 2010). Additionally, cumulative thresholds, known as critical loads, have been established for Colorado's Class I areas by the National Park Service (NPS) and the U.S. Department of Agriculture (USDA) U.S. Forest Service (USFS). Critical loads are deposition levels, often expressed as a range (minimum and maximum), below which significant ecosystem effects do not occur and are a property of the individual ecosystem's components (species) functionality.

Visibility impairment or haze is caused when sunlight encounters tiny pollution particles in the atmosphere and is either absorbed or scattered, which reduces the clarity and color of what can be seen. Deciviews (dv) and standard visual range (SVR) are terms in which to express visibility. A change of one dv is approximately a 10% change in the light extinction coefficient (i.e., light that is scattered or absorbed and does not reach the observer), which is a small but usually perceptible scenic change. Class I areas have legislative mandates to provide for natural visibility conditions such that visitors can experience a pristine environment free from observable pollution effects. The ability of a pollutant to cause various degrees of visibility impacts is primarily a function of its physical size, chemical composition, and other properties. The FLMs use a DAT of 0.5 dv for projects that contribute to a visibility problem and a value of 1.0 dv for projects that cause visibility issues (FLAG 2010).

The closest Class I area to the Project Area is the Great Sand Dunes National Park and Preserve, at about 38 miles (62 kilometers [km]) to the northwest. Visibility monitoring data for the Park show significant improvement trends over the monitoring period for both the clearest and haziest days. There are no deposition monitoring data available at the Park, but NPS modeling data suggest that total nitrogen deposition may be above critical loads for certain species.

1.2.1 Colorado Air Quality Regulations

The project would be required to comply with all CDPHE-APCD regulations before commencing operation. Colorado Air Quality Control Commission Regulations applicable to emissions sources in the project area would include:

- Air Quality Standards, Designations and Emission Budgets (5 CCR 1001-14)
- Regulation 1 - Emission Control for Particulate Matter, Smoke, Carbon Monoxide and Sulfur Oxides (5 Colorado Code of Regulations [CCR] 1001-3)
- Regulation 3 - Stationary Source Permitting and Air Pollutant Emission Notice Requirements (5 CCR 1001-5)
- Regulation 8 - Control of Hazardous Air Pollutants (5 CCR 1001-10).

Additionally, Colorado has adopted a majority of the federal New Source Performance Standards (NSPS) as promulgated under Section 111 of the CAA. These are technology-based emissions standards which apply to specific categories of stationary sources. NSPS potentially applicable to the Project include the following subparts of 40 Code of Federal Regulations (CFR) Part 60:

- Subpart A – General Provisions, apply to the owner or operator of any stationary source that contains an affected facility. The provisions apply to facilities that commenced construction or modification after the date of publication of any proposed standard. Provisions of Subpart A apply to project sources that are affected by NSPS.
- Subpart Y – Coal Preparation and Processing Plants, applies to new coal preparation and processing plants. Coal preparation and processing plants break, crush, screen, clean, and/or use heat to dry coal at coal mines, power plants, cement plants, coke manufacturing facilities, and industrial facilities.

The subpart, revised on September 25, 2009, requires new coal preparation and processing plants to meet the limits set forth in the performance standard.

- Subpart IIII – Standards of Performance for Stationary Compression Ignition Engines, establishes emission standards and compliance schedules for the control of emissions from compression ignition (CI) internal combustion engines (ICE; diesel engines). The rule requires new engines of various horsepower classes to meet emissions standards for NO_x, VOCs, and particulate matter (PM). Owners and operators of stationary CI ICE that commenced construction after July 11, 2005 are subject to this rule.
- Subpart JJJJ – Standards of Performance for Stationary Spark-Ignition Internal Combustion Engines, establishes emission standards and compliance schedules for the control of emissions from spark ignition (SI) internal combustion engines. The rule requires new engines of various horsepower classes to meet increasingly stringent NO_x and VOC emission standards over the phase-in period of the regulation. Owners and operators of stationary SI ICE that commenced construction, modification, or reconstruction after June 12, 2006 are subject to this rule; standards will depend on the engine horsepower and manufacture date.

1.2.2 Greenhouse Gases

Another group of commonly emitted air pollutants are the greenhouse gases (GHGs). 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 CAA (FR EPA-HQ-OAR-2009-0171), the USEPA determined that GHGs are air pollutants subject to regulation. GHGs' status as pollutants are founded on the added long-term impacts they have on the climate due to their increased concentrations in the atmosphere. The USEPA has promulgated the Mandatory Reporting Rule (the Rule; 74 FR 56260, 40 CFR 98) to regulate GHG emissions and the industries responsible for them. Under the Rule, underground coal mines subject to the Rule are required to report emissions in accordance with the requirements of Subpart FF.

The GHGs include carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); and several fluorinated species of gases such as hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. CO_2 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). CH_4 is emitted during the production and transport of coal, natural gas, and oil. CH_4 also results from livestock and other agricultural practices and by the decay of organic waste in municipal solid waste landfills. N_2O is emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste. Fluorinated gases are powerful GHGs 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), but are not typically associated with BLM-authorized activities.

All of the different GHGs have various capacities to trap heat in the atmosphere, which are known as global warming potentials (GWPs). GWPs can be expressed for several different time horizons to fully account for the gases' ability to absorb infrared radiation (heat) over their atmospheric lifetime. The BLM uses the 100-year time interval because a majority of the climate change impacts derived from climate models are expressed toward the end of the century. Similarly, these models are often based on 100-year emissions projections, such that providing a 1 to 1 comparison of the emissions provides for a more meaningful and understandable analysis. CO_2 has a GWP of 1; therefore, for the purposes of analysis, a GHG's GWP is generally standardized to a CO_2 equivalent (CO_2e), or the equivalent amount of CO_2 mass the GHG would represent. GWP values change over time based on continued study and scientific understanding, and multiple citations exist where agencies and organizations may elect to specify one value over another for their purposes (e.g., accounting, reporting). For the purposes of this project, the BLM uses the Intergovernmental Panel on Climate Change (IPCC) - AR5 values for CH_4 (28 for the gas alone and 36 with climate feedbacks), and the IPCC - AR4 value for N_2O (298). For GHG reporting in 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, the USEPA uses a GWP value of 25 for CH_4 and, for the purposes of this evaluation, that value will be used for this document.

1.2.3 Source and Emissions Data

All emissions sources fall into two broad categories for regulatory purposes: stationary and mobile, where each are typically regulated according to their type and classification.

Stationary sources are non-moving, fixed-site producers of pollution such as power plants, petro-chemical refineries, manufacturing facilities, and other industrial sites such as oil and gas production pads and coal mines. 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 either major or 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. A stationary source that takes federally enforceable limits on production, consumptions rates, or emissions to avoid major source status are called synthetic minors. The CDPHE, APCD has authority under their USEPA-approved SIP to regulate and issue air permits for stationary sources of pollution in Colorado.

Mobile sources include motor vehicles, engines, and equipment that can be moved from one location to another. Due to the large number and variety of these sources, which includes cars, trucks, buses, construction equipment, lawn and garden equipment, aircraft, watercraft, motorcycles, and their ability to move across traditional regulatory jurisdictions (i.e., state lines), mobile sources are regulated differently than stationary sources. In general, USEPA and other federal entities retain authority to set emissions standards for these sources depending on their type (on-road, off-road, and non-road), classification (e.g., light-duty, heavy-duty, horsepower rating, weight, fuel types), and the year of manufacture or (in some circumstances) their reconditioning. For example, the USEPA sets emissions standards for non-road diesel engines for hydrocarbons, NOx, CO, and PM. The emissions standards are implemented in tiers by year, with different standards and start years for various engine power ratings. The new standards do not apply to existing non-road equipment. Only equipment built after the start date for an engine category (1999-2006, depending on the category) is affected by the rule. Mobile sources in Colorado are not regulated by the state unless they are covered under an applicable SIP, usually as part of an on-road inspection and maintenance program (i.e., emissions testing).

Note: Over the life-of-project, the fleet of on-road and non-road equipment employed at the New Elk Mine is likely to turn over, and higher-emitting engines will be replaced with more fuel-efficient lower-emitting engines.

As stated above, air quality for any given area is influenced in part by the amount of pollutants released within and upwind of the area of interest (i.e., emissions loading). The following National Emissions

Inventory (NEI) Data provided in **Table 6** show the amount of pollutants released within the project area (Las Animas County), as well as the top emitting sector in terms of percent contribution for each pollutant.

Table 6 2014 NEI Data, Las Animas County (tons/year)

Pollutant	Emissions (tons)	Largest Contributing Sector	Sector % Contribution
PM_{10}	2,714	Unpaved Road Travel	45
$PM_{2.5}$	865	Wildfires	27
VOC	38,361	Oil and Gas Production	10
NO_x	11,404	Natural Gas Fuel Combustion	38
CO	23,557	Oil and Gas Production	25
SO_2	77	Oil and Gas Production	38
CO_2	224,004	Mobile On-Road Diesel Light Duty Vehicles	48
CH_4	213	Wildfires	62
N_2O	3	Mobile On-Road Diesel Light Duty Vehicles	99
HAPs	7,931	Oil and Gas Production	6

Notes:
The USEPA 2014 NEI data include all emissions-generating activities (sectors) within a reporting area (county). The GHG data (CO_2, CH_4, N_2O) are limited to mobile sources and fires only. The table data also exclude biogenic emissions from vegetation and soils, which accounted for the largest percentages of VOC, CO, and HAPs (for these pollutants the second largest contributor is shown).

According to the CDPHE Air Pollutant Emission Notice (APEN) database, there are 285 sources of emissions currently located within 10 km of the New Elk Mine. Emissions for these sources are summarized in **Table 7,** and the locations of NO_x and PM_{10} sources relative to New Elk are shown on **Figure 2**. The region is generally rural, and the emissions sources are dominated by oil and gas production and aggregate (sand and gravel) mining/processing. The CDPHE database includes all sources of air emissions required by law to acquire a permit. Sources such as dust from dirt roads, agricultural operations, recreational activities, and automobile use are not included because they are not regulated as stationary industrial sources (although they can influence air quality regionally).

Table 7 Proximity Air Pollution Emission Notice (APEN) Summary

Annual Actual Pollutant Emissions (tons per year [tpy])						
Pollutants	PM_{10}	$PM_{2.5}$	CO	NO_x	SO_2	VOC
Emissions	7.3	3.8	3,592	2,804	0.4	110
Source Count	32	31	285	285	28	285
% NEI	0.26%	0.44%	15%	25%	0.52%	0.28%

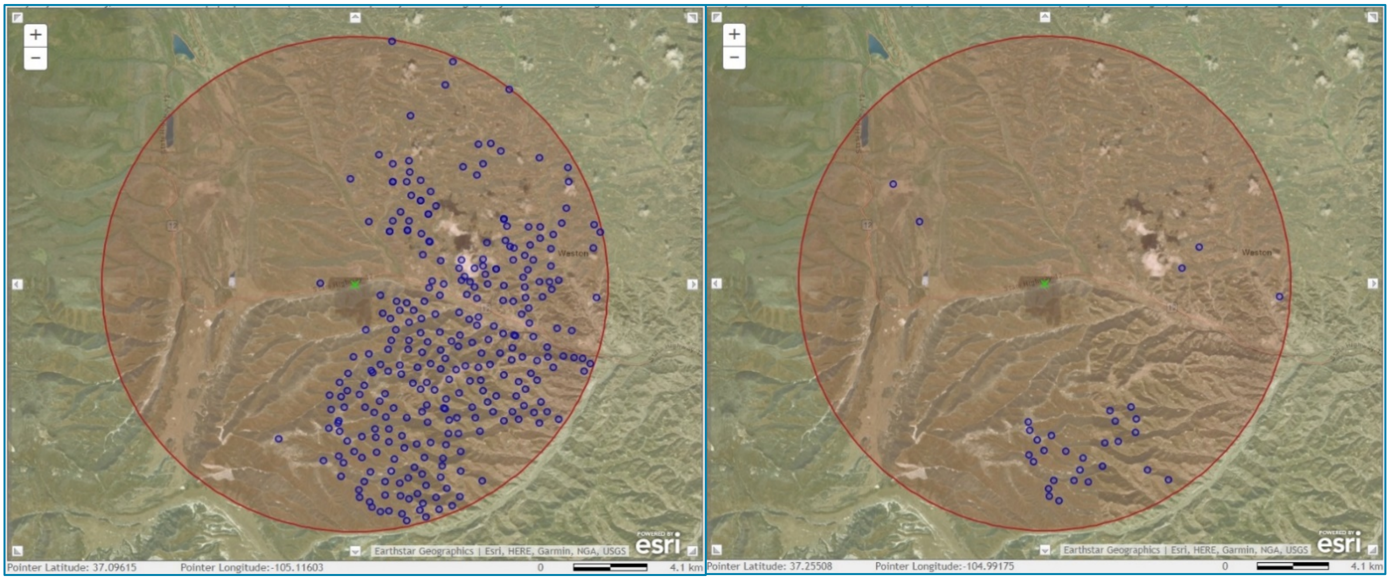

Figure 2 Spatial Relationship of APEN Sources to New Elk Mine (NO_x on left, PM_{10} on right)

Stationary sources at the New Elk Mine are authorized by CDPHE to operate under different APCD Permits (84LA074F-1, 84LA074F-2, 09LA0590). The APCD permits only cover sources of particulate matter. None of the other stationary sources at the mine generate pollutants in quantities significant enough to warrant permitting. In late 2011, the mine submitted a modification request to amend existing permits to allow for an increase in production throughput, the addition of two new exhaust shaft fans, and the addition of a waste rock crushing unit. However, it appears that the requested revisions were never issued before the mine was idled. New Elk also holds a permit (10LA1643) to perform stockpiling and loading operations at the Jansen Rail Yard in Trinidad, Colorado. All of the known existing authorizations for the mine are shown in **Table 8**.

Table 8 New Elk Permit Emissions (tpy)

Permit No.	AIRS ID	Permitted Pollutant	Description	Permitted Emissions[1]
84LA074F-1 || (2009)	001	PM PM_{10}	Coal Prep and Wash Plant	0.22 0.11
84LA074F-1 || (2009)	001	PM PM_{10}	Fugitive Dust (stockpile management)	2.05 0.97
84LA074F-2 || (2009)	002	PM PM_{10}	Refuse Transport and Disposal (fugitive emissions)	0.9 0.4
09LA0590 || (2009)	005a, b	PM PM_{10}	Vent Fans (300K & 100K cubic feet per minute [cfm])	6.6 6.6

Table 8 New Elk Permit Emissions (tpy)

Permit No.	AIRS ID	Permitted Pollutant	Description	Permitted Emissions[1]
10LA1643 || (2012)	006	PM PM_{10} $PM_{2.5}$	Railyard Operations Process Emissions (conveyors, transfer points, train loading)	1.5 0.7 0.1
10LA1643 (2012)	006	PM PM_{10} $PM_{2.5}$	Railyard Operations Fugitive Emissions (truck traffic, stockpile management)	5.6 1.4 0.1
All	All	PM PM_{10} $PM_{2.5}$	Totals	16.87 10.18 0.2

Notes:

1 Permitted emissions include fugitive emissions. APCD did not require $PM_{2.5}$ emission limits until issuance of permit 10LA1643 in 2012.

1.2.3.1 Climate Change

The following information is summarized from the IPCC (IPCC 2014). There is broad scientific consensus that human actions are changing the chemical composition of Earth's atmosphere. Activities such as fossil fuel combustion, industrialization, deforestation, and other changes in land use are resulting in the accumulation of trace GHGs such as CO_2, CH_4, N_2O, and several industrial gases in the Earth's atmosphere. Scientists believe that increases in atmospheric GHG concentrations result in an increase in the Earth's average surface temperature, primarily by trapping and thus decreasing the amount of heat energy radiated by the Earth back into space. The phenomenon is commonly referred to as global warming. Global warming is expected, in turn, to affect weather patterns, average sea level, ocean acidification, chemical reaction rates, and precipitation rates, all of which is collectively referred to as climate change. Current understanding of the climate system comes from the cumulative results of observations, experimental research, theoretical studies, and model simulations.

The IPCC is the leading international scientific body under the auspices of the United Nations charged with reviewing and assessing the most recent scientific, technical, and socioeconomic information produced worldwide relevant to the understanding of climate change. IPCC assessment reports provide rigorous and balanced scientific information that reflect a range of views and expertise to ensure an objective and complete assessment of the current information. The IPCC Fifth Assessment Report (AR5) (IPCC 2013) uses terms to indicate the assessed likelihood of an outcome, ranging from exceptionally unlikely (0 to 1 percent) to virtually certain (99 to 100 percent probability), and level of confidence ranging from very low to very high. The work done by the organization is policy-relevant and yet policy-neutral, never policy-prescriptive, and forms the basis for the summarized information below.

Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over time spans of decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, and sea levels have risen. Each of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850. In the Northern

Hemisphere, 1983–2012 was likely the warmest 30-year period of the last 1,400 years (medium confidence). The globally averaged combined land and ocean surface temperature data, as calculated by a linear trend, show warming of 0.85 [0.65 to 1.06] °C (degrees Celsius), over the period 1880 to 2012. In Colorado, the statewide annual average temperatures have increased by 2.0°F and 2.5°F over the past 30 and 50 years, respectively. Warming trends have been observed over this period in most parts of the state and show that daily minimum temperatures have warmed more than daily maximum temperatures. Additionally, temperature increases have occurred in all seasons. No long-term trends in average annual precipitation (30-50 years) have been detected across Colorado, although since 2000, the state has experienced below-average annual precipitation and snowpack. The warming trends have contributed to an earlier shift in snowmelt and peak runoff timing in spring by approximately 1 to 4 weeks.

Ocean warming has dominated the increase in energy stored in the climate system, accounting for more than 90% of the energy accumulated between 1971 and 2010 (high confidence). On a global scale, the ocean warming is largest near the surface, and the upper 75 meters (m) warmed by 0.11 (0.09 to 0.13) °C per decade over the period of 1971 to 2010. More than 60% of the net energy increase in the climate system is stored in the upper ocean (0 to 700 m), and about 30% is stored in the ocean below 700 m (40-year period from 1971 to 2010). The rate of sea level rise since the mid-19th century has been larger than the mean rate during the previous two millennia (high confidence). Over the period 1901 to 2010, global mean sea level rose by 0.19 (0.17 to 0.21) m. It is very likely that the mean rate of global averaged sea level rise was 1.7 (1.5 to 1.9) mm yr–1 between 1901 and 2010, 2.0 (1.7 to 2.3) mm yr–1 between 1971 and 2010, and 3.2 (2.8 to 3.6) mm yr–1 between 1993 and 2010, a trend that is increasing.

The driver for the buildup in heat within the climate system is best described in terms of radiative forcing (RF). The term describes the energy balance that will occur (i.e., heating [+] or cooling [-]) in units of W m–2. The total anthropogenic RF for 2011 relative to 1750 was 2.29 (1.13 to 3.33) W m−2 (includes both heating and cooling parameter estimates). For well-mixed GHGs, the total positive forcing is estimated to be 2.83 (2.54 to 3.12) W m–2. The largest contribution to total RF since 1750 is the increase in the atmospheric concentration of CO_2. Emissions of CO_2 alone caused an RF of 1.82 (± 0.19) W m–2 (64%), while CH_4 caused an RF of 0.48 (± 0.05) W m−2 (17%). The data highlight CH_4's important role as a potent GHG given its RF value in relation to its atmospheric loading trend, approximately 556 teragrams per year (Tg yr–1) (64% anthropogenic, 36% natural) and relatively short atmospheric lifetime (12 years). N_2O has the third largest forcing of the anthropogenic gases, at 0.17 (± 0.03) W m–2 (6%). Collectively, the three GHGs of concern account for approximately 87% of the positive forcing within the climate system.

Between 1750 and 2011, cumulative anthropogenic CO_2 emissions emitted to the atmosphere were approximately 2,040 ± 310 gigatons of carbon dioxide ($GtCO_2$). About 43% of these emissions have remained in the atmosphere (880 ± 35 $GtCO_2$); the rest was removed from the atmosphere and stored in natural terrestrial ecosystems (plants and soils – 29%) and in the oceans (28%). Although CO_2 levels in the atmosphere have varied perpetually throughout Earth's history (along with corresponding variations in climatic conditions), industrialization and the burning of carbon-based fossil fuel sources has caused CO_2 concentrations to increase measurably, from approximately 280 ppm in 1750 to 400 ppm in 2015. The rate of change has also been increasing. This fact is demonstrated by data from the Mauna Loa CO_2 monitor in Hawaii that documents atmospheric concentrations of CO_2 going back to 1960, at which point the average annual concentration was recorded at approximately 317 ppm. The record shows that approximately 70% of the increases in atmospheric CO_2 concentration since pre-industrial times (1750) occurred within the last 55 years. The trend corresponds to an increasing population and rising standards of living and modernization around the globe. From pre-industrial times to present, emissions from fossil fuel combustion and cement production have released 375 (345 to 405) GtC to the atmosphere (68%), while deforestation and other land use change are estimated to have released 180 (100 to 260) GtC (32%). Concentrations of CO_2, CH_4, and N_2O now substantially exceed the highest concentrations recorded in ice cores during the past 800,000 years. Since pre-industrial times, the estimated concentrations of CH_4 have more than doubled (722 ppb to 1,803ppb), while N_2O concentrations have increased by a fifth (270 ppb to 324 ppb).

1.3 Environmental Effects

1.3.1 No Action Alternative

Under the No Action Alternative, NECC would mine privately owned coal tracts for the estimated operational life of the mine (approximately 30 years). During this time, emissions of criteria pollutants and GHGs would occur at the mine. Except for some of the particulate matter (fugitive dust), all the directly emitted criteria pollutants from the New Elk Mine's operations are from fuel combustion sources, such as mobile mining equipment, haul trucks, and stationary sources such as emergency generators and coal conveyance systems. Many of these sources will also produce GHG emissions as well. Coal mine methane (CMM) may be directly emitted by the ventilation air handling system required by the Mine Safety and Health Administration (MSHA) to reduce the combustion/explosion potential of the mine's underground atmosphere. Historical levels of the gas in the coal formation, overburden, and surrounding strata suggest that CH_4 drainage wells will not be required at New Elk.

Indirect air emissions for the mine's operations were estimated for reasonably foreseeable activities, including, coal transport, mine worker commutes, and coal coking. NECC markets its metallurgical coal for export to international steel companies. For the purposes of this analysis, the following assumptions will be used to estimate the worst-case transport emissions. Clean coal would be hauled from the mine by truck to the Jansen Yard near Trinidad, Colorado, where it would be loaded into rail cars for transport by locomotive to a domestic shipping port. The coal would then be loaded into cargo ships for ocean-going transport to an international destination port. All of the exported coal would be combusted to coke for use in the production of steel or iron at an unknown international location.

All of the direct and indirect emissions resulting from New Elk's mining activities are estimated at the levels calculated below and are shown in **Table 9** and **Table 10**, respectively. The conservative estimates are based on NECC producing up to 2,200,000 tons of coal per year. Unless otherwise noted, pollutant emission calculations are based on emission factors from USEPA document AP 42, Fifth Edition, Compilation of Air Pollutant Emissions Factors, Volume 1: Stationary Point and Area Sources (1995 *et seq.*).

***Mine Generator Engines*:** Propane and gasoline engines are currently owned by NECC and operate during mining activities. Two propane engines are used for Dispatch backup power (33-horsepower [hp]) and emergency escape hoist power (235 hp). One gasoline engine (13 hp) is used for as-needed power. GHG emissions for these engines are calculated with emission factors from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases, and are based on projected annual operating hours. Criteria pollutant emissions for the propane engines are calculated with emission factors from AP-42, Chapter 3.2, Natural Gas-fired Reciprocating Engines because emission factors are not available in AP-42 for propane-fired engines (USEPA 2000). Criteria pollutant emissions for the gasoline engine are calculated with emission factors from AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines (USEPA 1996a). Emissions for all engines are based on projected annual operating hours.

Mine Surface Point Sources: Once mined from underground, raw coal is processed through a series of material handling steps to separate it into clean coal and waste rock. These material handling steps include conveyor transfers, placement in storage silos/bins, crushing, and truck loading. Most of these operations have some type of control (such as a total enclosure, stacking tube, or reclaim tunnel) and are thus designated as 'point sources' because they are not fugitive sources. Particulate emissions (PM, PM_{10}, and $PM_{2.5}$) for these activities are based on the December 30, 2011 APEN/permit modification package submitted to the CDPHE by NECC (NECC 2011). NECC developed these emissions using AP-42, Chapter 13.2.4, Aggregate Handling and Storage Piles. The APEN emissions are calculated with throughput rates for each type of material: raw coal (5,500,000 tpy), clean coal (3,300,000 tpy), and waste rock (2,200,000 tpy). Emissions for these activities are scaled between the throughput rates in the APEN and the projected throughput rates used for this analysis: raw coal (3,000,000 tpy), clean coal (2,200,000 tpy), and waste rock (800,000 tpy).

Underground Mining Activities**:** Coal is recovered with underground mining equipment to meet the average annual production level of 2,200,000 tpy. Underground equipment may consist of, but not be limited to, continuous miners, feeder breakers, shuttle cars, section scoops, section forklifts, construction roof bolters, can manipulators/beam setters, and supervisor/maintenance vehicles. This equipment will generate emissions of PM, PM_{10}, and $PM_{2.5}$ by actively mining the ore body, handling the ore, and travel on unpaved roads underground. (Some of the equipment would be diesel-powered and would generate fuel combustion emissions. These are addressed below under *Mine Nonroad Mobile Diesel Engines*.) Particulate emissions for these activities are taken from the December 30, 2011 APEN/permit modification package submitted to the CDPHE by NECC (NECC 2011). The emissions are for underground mining activities generating particulates vented from the mine by the Bates Portal Fan, and are based on 1.0 milligrams per cubic meter (mg/m^3) concentrations of PM, PM_{10}, and $PM_{2.5}$ and a total combined continuous ventilation rate of 450,000 actual cubic feet per minute (acfm). Because the APEN emissions are not dependent on the mine production rate, they do not need to be scaled to the production level of 2,200,000 tpy. Particulate concentrations are based on the maximum allowable by MSHA: 1.0 mg/m^3.

Mine GHG Ventilation**:** As a result of coal extraction, CH_4 trapped in the coal seam is released. This CH_4 is removed from the mine and exhausted to the atmosphere by forced-air ventilation at mine portals. The amount of CH_4 ventilated is calculated based on a total ventilation rate of 450,000 acfm (NECC 2019) and an estimated average methane concentration of 1 percent in the ventilation air (NECC 2018). To determine total and annual GHG emissions released, the quantity of CH_4 ventilated from the mine is calculated with Equation FF-1 from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases. The CH_4 emissions are multiplied by a Global Warming Potential of 25 to calculate metric tons of CO_2e (USEPA 2015).

Mine Nonroad Mobile Diesel Engines**:** Coal is recovered with diesel-powered equipment to meet the average annual production level of 2,200,000 tpy for mining operations. Underground diesel mobile equipment may consist of, but not be limited to, shuttle cars, section scoops, section forklifts, construction roof bolters, can manipulators/beam setters, and supervisor/maintenance vehicles. On the surface, coal is managed into stockpiles and loaded into over-the-road transport trucks with diesel-powered surface equipment. This equipment may consist of, but not be limited to, bulldozers, front-end loaders, graders, and trucks. GHG emissions for these underground and surface nonroad mobile engines are calculated with emission factors from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases, and are based on projected diesel fuel usage. Criteria pollutant emissions for these nonroad mobile diesel engines are calculated with emission factors from Table 6 of 40 CFR 1039.102, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines. This table provides Interim Tier 4 exhaust standards for 2011 - 2014 nonroad CI engines between 174 hp and 751 hp; which are assumed to represent the mine fleet of nonroad equipment. 40 CFR 1039.102 does not provide an SO_2 emission factor; Therefore, SO_2 is estimated from AP-42, Table 3.4-1 for Large Stationary Diesel and Dual-Fuel Engines (USEPA 1996b). Ultra-low sulfur diesel fuel (15 ppm sulfur) will be used in the vehicles/equipment. Emissions are based on projected annual diesel fuel usage.

Surface Dozing/Stockpiles: On the surface, coal is placed into stockpiles with bulldozers. The activity of the bulldozers handling the coal and wind erosion from the stockpiles generates fugitive particulate emissions as PM, PM_{10}, and $PM_{2.5}$. Particulate emissions data for these activities are based on the December 30, 2011 APEN/permit modification package submitted to the CDPHE by NECC (NECC 2011). NECC developed these emissions using AP-42, Chapter 11.9, Western Surface Coal Mining. The dozing emissions are based on pound per hour emission factors with operations conducted 8,760 hours per year. Dozing emissions are controlled with naturally occurring moisture or use of water sprays. The stockpile emissions are based on surface areas for raw coal, clean coal, waste rock, and the Development Waste Disposal Area (DWDA). Stockpile emissions are scaled to the permit modification based on projected throughput. Stockpile emissions are controlled with naturally occurring moisture or use of water sprays.

Table 9 Projected Direct Emissions (tpy)

Source	PM_{10}	$PM_{2.5}$	VOC	NO_X	CO	SO_2	CO_2e[1]	CO_2	N_2O	CH_4
Generator Engine – Propane	5.58E-07	5.58E-07	0.011	0.030	2.29E-03	4.26E-06	3.45	3.75	1.79E-04	3.57E-05
Generator Engine – Gasoline	2.44E-04	2.44E-04	0.0051	3.72E-03	2.35E-03	2.00E-04	0.46	0.50	2.12E-05	4.25E-06
Nonroad Mobile Diesel Engines	1.62	1.62	15.38	32.37	283.24	0.6	51,595	56,167	2.28	0.46
Mine Ventilation	7.38	7.38	NA	NA	NA	NA	1,124,730	NA	NA	49,578
Worker Commutes	51.83	5.49	1.20	1.20	15.81	0.01	1,120	1,224	0.03	0.05
Surface Stationary Point Sources	4.5	0.69	NA	NA	NA	NA	NA	NA	NA	NA
Surface Dozing/Stockpiles	26.95	4.09	NA	NA	NA	NA	NA	NA	NA	NA
Surface Unpaved Roads	10	1	NA	NA	NA	NA	NA	NA	NA	NA
Truck Transport to/from Jansen Rail Yard	1.26	1.15	2.64	53.3	15.08	0.31	6,352	6,990	0.029	0.031
Subtotal of Direct Sources	**103.53**	**21.42**	**19.23**	**86.91**	**314.13**	**0.91**	**1,183,800**	**64,385**	**2.34**	**49,579**

Notes:

1 CO_2e units are metric tons

Table 10 Projected Indirect Emissions (tpy)

Source	PM_{10}	$PM_{2.5}$	VOC	NO_X	CO	SO_2	CO_2e[1]	CO_2	N_2O	CH_4
Jansen Rail Yard Activities and Loading	6.21	0.71	0.5	1.06	9.29	1.96E-02	1,691	1,841	0.075	0.015
Rail Transport to Domestic Port	22.74	22.05	37.35	936.69	283.74	0.85	83,915	91,642	2.18	7.27
Domestic Port Activities & Loading	6.21	0.71	0.5	1.06	9.29	1.96E-02	1,691	1,841	0.075	0.015
Ship Transport to International Port	65.37	59.81	69.55	1,250	153	552.2	1,067,433	1,163,712	33.94	99.40
International Port Activities & Loading	6.21	0.71	0.5	1.06	9.29	1.96E-02	1,691	1,841	0.075	0.015
Coal Coking (combustion)	NA	NA	NA	NA	NA	NA	6,243,039	6,834,384	96.98	661.86
Subtotal of Indirect Sources	**106.74**	**84.00**	**108.4**	**2,189.44**	**464.59**	**553.11**	**7,399,460**	**8,095,262**	**133.32**	**768.58**

Notes:

1 CO_2e units are metric tons

Surface Unpaved Roads: Fugitive particulate emissions (PM, PM_{10}, and $PM_{2.5}$) are generated from the travel of haul trucks at the mine surface beginning their trips to haul coal to the Jansen Rail Yard. Particulate emissions values are based on the December 30, 2011 APEN/permit modification package submitted to the CDPHE by NECC (NECC 2011). NECC developed these emissions using AP-42, Chapter 13.2.2, Unpaved Roads, based on hauling 1,000,000 tpy of clean coal 1 mile round-trip from the mine to Highway 12 for transport to the Jansen Rail Yard. These emissions only address fugitive dust emissions that will occur at the mine property and not beyond the mine boundary once trucks reach Highway 12. Emissions are scaled from the APEN based on the clean coal throughput basis: 1,000,000 tons for the APEN and 2,200,000 tons for the conservative future projection. The NECC mine plan calls for moving coal by the re-established rail line between the mine and the Jansen Rail Yard when production exceeds 1 million tons of clean coal per year. Because the timing of meeting this threshold is unknown, this evaluation calculates emissions based on moving all coal by truck to the Jansen Rail Yard. Emissions are controlled with naturally occurring moisture or use of water sprays.

Mining Worker Commutes: Criteria emissions and GHG emissions were estimated for workers commuting to the mine site associated with vehicle exhaust and fugitive particulate emissions from vehicle travel on paved and unpaved roads. Emissions from fuel combustion in vehicle engines were estimated with the USEPA computer software program Motor Vehicle Emission Simulator 2014b (MOVES 2014b; USEPA 2018b). Fugitive particulate emissions were estimated using equations from USEPA AP-42 (USEPA 2011, USEPA 2006). Worker commute emissions are based on 175 mine workers traveling 50 miles roundtrip between home and the mine, 365 days a year. Acknowledging that some portion of worker travel may be on unpaved roads, emissions were estimated assuming 5% travel on unpaved roads and 95% on paved roads. Emissions are based on workers driving the 2020 vehicle fleet for Las Animas County, with associated emission factors. This provides a conservative overestimate of projected future emissions because, in years after 2020, older vehicles used by workers will be replaced with cleaner emitting vehicles in the years to come.

***Truck Transport to/from Jansen Rail Yard*:** Coal is transported by truck to the Jansen Rail Yard in Trinidad, Colorado until the rail line between the mine and the rail yard is re-established. Round-trip travel is calculated because it is anticipated that NECC would contract with a trucking company to specifically move coal to the Jansen Rail Yard and then return to the mine to repeat the trip. The one-way distance between the mine and Jansen Rail Yard is approximately 25 miles. Each truck can carry approximately 25 tons. GHG and criteria pollutant emissions are calculated assuming that 2,200,000 tons of coal are transported by truck annually. The NECC mine plan calls for moving coal by the re-established rail line between the mine and the Jansen Rail Yard when production exceeds 1 million tons of clean coal per year. Because the timing of meeting this threshold is unknown, this evaluation calculates emissions based on moving all coal by truck to the Jansen Rail Yard. Moving materials by rail typically results in lower emissions than truck transport because more freight can be moved with the same amount of fuel. GHG emissions were calculated using the World Resources Institute GHG Protocol Tool for Mobile Combustion, Version 2.6 (World Resources Institute [WRI] 2015). Criteria pollutant emissions were calculated using emission factors from Table 2 of USEPA document EPA420-F-08-027, Average In-Use Emissions from Heavy-Duty Trucks, October 2008 (USEPA 2008). This document does not provide an SO_2 emission factor; therefore, SO_2 is estimated from AP-42, Table 3.4-1 for Large Stationary Diesel and Dual-Fuel Engines (USEPA 1996b). Ultra-low sulfur diesel fuel (15 ppm sulfur) is used in the vehicles/equipment. Emissions are based on projected annual miles of round-trip truck travel between the mine and the Jansen Rail Yard.

Yard and Port Activities – Jansen Rail Yard, Domestic Port, International Port: Coal arriving at the Jansen Rail Yard is typically placed in rail cars with electric conveyor belts. Currently, no coal contracts are in place to estimate the actual emissions from rail shipments of the produced coal. It is unclear which domestic ports would be used to export coal. The coal is transported to a domestic port and then shipped to an international port. The Jansen Rail Yard Permit also allows for loading by front-end loader if necessary. During delivery, storage, and handling of the coal, PM, PM_{10}, and $PM_{2.5}$ emissions will be generated from conveyors, transfer points, truck traffic on site unpaved roads, wind erosion from the coal stockpile, and loading of coal to trains. Particulate emissions values are based on Construction Permit 10LA1643, dated May 22, 2012, for the Jansen Rail Yard, issued by the CDPHE (CDPHE 2012). The emissions are based on loading 1,000,000 tpy of clean coal to trains. To estimate Jansen Rail Yard emissions related to conservative projection, emissions are scaled to the permit based on the clean coal throughput: 1,000,000 tons for the APEN and 2,200,000 tons for conservative projection. Emissions are controlled with partial enclosures, naturally occurring moisture, or use of water sprays. Because materials such as coal are handled and loaded in developed ports with similar equipment (such as conveyors and loaders), it is anticipated that the domestic port and the international port would have similar operations. In the absence of information for these similar activities at the originating port and the receiving port, it is assumed that the Jansen Rail Yard activity emissions are representative of the emissions at the domestic port and the international port.

***Loading Equipment Engines – Jansen Rail Yard, Domestic Port, International Port*:** Coal is loaded for transport via rail and ship typically with electric conveyor belts. The Jansen Rail Yard air permit has provisions for loading by front-end loader, and the equipment for the domestic port and the international port is assumed to be the same or similar for the purposes of estimating emissions. GHG emissions for these engines were calculated with emission factors from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases, and are based on the annual equipment operation. Criteria pollutant emissions for these engines are calculated based on the Caterpillar 980 front-end loader listed in Construction Permit 10LA1643, dated May 22, 2012, for the Jansen Rail Yard, issued by CDPHE (CDPHE 2012). Criteria pollutant emissions for these nonroad mobile diesel engines are calculated with emission factors from Table 6 of 40 CFR 1039.102, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines. This table provides Interim Tier 4 exhaust standards for 2011 - 2014 nonroad CI engines between 174 hp and 751 hp. The Caterpillar 980 front-end loader has a 431 hp diesel engine (Caterpillar 2018). 40 CFR 1039.102 does not provide an SO_2 emission factor; therefore, SO_2 is estimated from AP-42, Table 3.4-1 for Large Stationary Diesel and Dual-Fuel Engines (USEPA 1996b). It is assumed that ultra-low sulfur diesel fuel (15 ppm sulfur) is used in the vehicles/equipment. Emissions are based on engine horsepower and annual operating hours.

***Rail Transport to Domestic Port*:** Currently, no coal contracts are in place to estimate the actual emissions from rail shipments of the produced coal. It is unclear which domestic ports would be used to export coal. For the purposes of estimating emissions, it was assumed that coal will be transported from the Jansen Rail Yard for a one-way distance of 1,500 miles (to account for multiple potential domestic shipping ports). Round-trip travel is not calculated because it is expected that the transporting railroad would have return freight haulage for other customers. GHG emissions assume that 2,200,000 tons of coal are transported by rail annually and are calculated using the World Resources Institute GHG Protocol Tool for Mobile Combustion, Version 2.6 (WRI 2015). Criteria pollutant emissions assume that 2,200,000 tons of coal are transported by rail annually and are calculated using emission factors for line-haul locomotives from USEPA document EPA-420-F-09-025, Emission Factors for Locomotives, April 2009 (USEPA 2009a). The locomotive diesel fuel usage is estimated at 400 ton-miles per gallon (USEPA 2009a). The

USEPA document Emission Factors for Locomotives, EPA-420-F-09-025, April 2009 does not provide a CO emission factor; therefore, the CO emission factor is from 40 CFR 1033.101, Table 1 for 2005 to 2015 or later line-haul locomotives.

***Ship Transport to International Port*: ** Currently, no coal contracts are in place to estimate the actual emissions from cargo shipments of the produced coal. It is unclear which domestic and international ports would be used to export coal. For the purposes of estimating emissions, it was assumed that coal would be transported by dry bulk cargo ship for a one-way distance of 10,000 miles between the domestic port and the international port. Round-trip travel is not calculated because it is expected that the transporting shipper would have return cargo haulage for other customers. GHG emissions and criteria pollutant emissions are calculated assuming that 2,200,000 tons are transported by ship annually. Each cargo ship is assumed to have a carrying capacity of 69,000 tons (Insurance Marine News [IMN] 2018), propulsion engine power of 8,000 kilowatts (kW; approximately 10,700 hp; USEPA 2009b), and an average cruising speed of 16.7 miles per hour (USEPA 2009b). GHG emissions are calculated using the World Resources Institute GHG Protocol Tool for Mobile Combustion, Version 2.6 (WRI 2015). Criteria pollutant emissions are calculated using emission factors from USEPA, Current Methodologies in Preparing Mobile Source Port-Related Emissions Inventories, Final Report, April 2009, Table 2-9 (USEPA 2009b) and Table 1 of 40 CFR 1042.104, Exhaust Emission Standards for Category 3 Engines, for Tier 2 2011-2015 engines.

***Combustion of Coal Coke Overseas*: ** Overseas, the NECC metallurgical coal is combusted to coke for use in the production of steel or iron at an unknown location. GHG emissions are calculated assuming an average annual coal usage rate of 2,200,000 tons. GHG emissions are calculated with emission factors from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases. Criteria pollutants for coking of coal and for production of steel or iron overseas are not evaluated here because it is difficult to estimate these emissions with a reasonable degree of confidence given the unknown process equipment, firing practices, and control equipment that may be used by foreign steel or iron producers. The effect of criteria pollutant emissions from these operations will be limited to local or regional impacts at the overseas location that are beyond the scope required for a NEPA evaluation.

To estimate the potential impacts of the mine's emissions on nearby receptors, the BLM is providing a screening analysis using USEPA's regulatory atmospheric dispersion model, AERMOD. AERMOD is a steady-state dispersion model designed to estimate short-range (up to 50 km) dispersion of air pollutant emissions from stationary industrial sources. For this analysis, we estimated impacts from direct sources of emissions at the mine including the mine vent (PM_{10}, $PM_{2.5}$, NO_X, and CO), conveyor systems (PM_{10} and $PM_{2.5}$), and stockpile management (PM_{10} and $PM_{2.5}$).

To model the potential worst-case impacts from mining operations, two pseudo sources were created to handle the various operations that occur above and below ground. Surface sources were modeled as a single large volume source given that the facility sources (stockpiles, conveyors, prep plant) are all centrally located and similarly accessible to handling equipment (nonroad sources). Initially, two volume sources were developed to analyze the main facility operations and the refuse disposal area. However, given the similar parameters between the sources (lateral dimension – 100 m and distance to the nearest receptor in ambient air – 550 m), and the fact that the screening mode of AERMOD is not concerned with the spatial relationship between the sources and receptors (model assumes that the source is blowing straight at the receptor), it was only necessary to model the higher of the two emissions sources to obtain the potential worst-case impacts. All underground sources of emissions were assumed to be emitted through the mine's vent fans. The vent fan was modeled as a point source and included 50% of the nonroad source emissions as an operational assumption (the remaining 50% were allocated to the surface volume source). AERSCREEN provides the maximum 1-hr concentration as a standard output. To determine the concentrations for the other averaging periods associated with the NAAQS, the 1-hour results were scaled in accordance with USEPA's guidance (AERSCREEN Users Guide). **Table 11** presents the absolute maximum 1-hour values and the scaled NAAQS percentages relative to the various standards for each pollutant.

Table 11 Projected Model Impacts

Source	Pollutant	Modeled Emission Rate (lbs/hr)	Maximum 1 hr Concentration (µg/m3)	% NAAQS	Standard	% NAAQS	Standard
Point	CO	45.39	259.4	0.65	1-hr	2.33	8-hr
	PM_{10}	2.625	15.0	1.0	Annual	NA	NA
	$PM_{2.5}$	2.625	15.0	12.5	Annual	25.72	24-hr
	NO_X	5.19	29.65	15.69	1-hr	5.59	Annual
Volume	CO	34.82	132.3	0.33	1-hr	1.19	8-hr
	PM_{10}	10.39	59.38	3.96	Annual	NA	NA
	$PM_{2.5}$	1.62	9.26	7.72	Annual	15.87	24-hr
	NO_X	3.98	22.74	12.03	1-hr	4.29	Annual

Abbreviations:
Lbs/hr pounds per hour

The results show that the mining operation will not cause an exceedance of the NAAQS for any pollutant. The $PM_{2.5}$ NAAQS analysis shows that the combination of the sources could contribute up to 41.59% of the annual standard (highest NAAQS related impact). The primary driver for the PM values is the mine vent emissions (non-diesel related). When developing an emissions inventory for a mine, engineers typically use an arbitrary emissions rate of 1.0 mg/m^3 (MSHA's allowable emissions rate) for all particulate matter emissions. This value assumes no speciation for the different aerometric sizes of the particulate (total suspended particulate [TSP], PM_{10}, $PM_{2.5}$) that constitute the make-up of the exhaust air, and instead simply assumes that all the particulates are classified as $PM_{2.5}$. While conservative from a permitting standpoint, this assumption can potentially inflate the $PM_{2.5}$ analysis. Sampling data available to BLM from other Colorado underground mines suggest the $PM_{2.5}$ value could be about half of the permitting inventory estimate. Further, the mine vent PM estimates are what would be considered primary PM, meaning that the emissions constitute earth-moving activates, not secondary formation from mobile sources. Consistent with other emissions factors for earth-moving activities, $PM_{2.5}$ is a fraction of the total particulate spectrum. For example, the stockpile management emissions factors show that $PM_{2.5}$ is approximately 15% of the PM_{10} value. Thus, the analysis is quite conservative.

Background ambient air concentrations for the NAAQS pollutants are not readily available for the vicinity surrounding the project area. The estimated impacts from the mine are relatively minor (less than 10% of NAAQS, save for $PM_{2.5}$), and are not expected to adversely impact air quality in the region. For example, monitoring data for the South-Central Air Pollution Control Region (CDPHE 2018) show that the 3-year average of 24-hour standard and the annual standard values for $PM_{2.5}$ were 16 µg/m^3 and 5.6 µg/m^3, respectively. These values would be considered conservative if applied to the project area, given that they are from Pueblo, Colorado, an area with significantly more population and industrial sources of air pollution than the project area. Adding the modeled concentrations to the Pueblo data (assumed background) would yield 24-hour and annual standard values of not more than 87.3% and 66.9% of the NAAQS, respectively. Similar outcomes would be certain for the other pollutants at the mine as well.

As stated earlier, the Mine never received any of the permit modifications NECC requested before idling operations at the facility. It is likely that the CDPHE will require regulatory modeling for any changes NECC anticipates needing for start-up. The analysis presented here is not designed to be a rigorous regulatory analysis.

No analysis is being provided for the indirect emissions sources because their location is presently unknown. However, it is unlikely that the minor amount of pollutants shown above for the stationary locations would have a significant impact on air quality. All transport-related emissions would have a similar negligible impact based on the fact that these emissions would be spread across what could potentially be thousands of miles, most of which could be on the open ocean, far removed from receptor populations.

With respect to potential O_3 formation, the mine is not a significant source of O_3 precursors (NO_X and VOC). Compared to the regional 10 km APEN levels (shown above), the direct precursor emissions from the mine represent just 3.1 and 16.4 percent of the NO_X and VOC, respectively. These percentages are slightly inflated as well because more than half of the truck trip traffic to Jansen Rail Yard will occur outside of the 10 km boundary used in the APEN analysis. Given that the mine's precursor emissions are so low on either an absolute or relative basis within the area of influence, and that the photochemical reactivity potential of CH_4 in the troposphere is considered negligible (40 CFR 51.100 [s]), the mine's operations are not expected to contribute significantly to regional O_3 formation potential. However, the BLM did analyze O_3 culpability at all the mines that produce federal minerals in Colorado cumulatively via the Colorado Air Resources Management Modeling Study (CARMMS). The CARMMS model, analysis scenarios, and results are described in the cumulative impacts section below.

The total HAP emissions from all sources at the mine is approximately 8.68 tons based on the ratio of HAPs to VOC in USEPA's NEI data for Non-Road Diesel Equipment for Las Animas County. These source types represent most of the VOC emissions generated by the mine. A majority of the mine's HAP emissions (68%) would be exhausted through the mine shaft ventilation system (this is true for the equipment's criteria emissions as well). As such, they are heavily diluted by the volume of makeup air required to keep the mine's atmosphere free from CH_4 that could accumulate in the underground environment as a result up exposing and removing the coal. Additionally, the mine shaft exhaust air has an initial inertial flux (i.e., vertical plume buoyancy, mechanically induced via the mine vent shaft fan) at the surface, which provides for increased dispersion potential as compared to the surface-based equipment exhaust. The USEPA (USEPA 2018c) provides Regional Screening Level (RSL) values for diesel emissions (as a whole) including a Reference Concentration (RfC), defined as an estimate of a daily inhalation exposure to the human population (including sensitive groups) that is likely to be without an appreciable risk of deleterious effects during a lifetime (5 µg/m^3). The rate at which HAPs are expected to be emitted cumulatively across the facility is approximately 0.7 gram per second (total HAP grams divided by 3,120 operating hours [assumed minimum] divided by 3,600 seconds per hour). Given the minor magnitude of these emissions, and the overall dispersion expected to occur within the facility before reaching a fence line, it is highly unlikely that ambient air quality would be impacted to a degree at which the public (for which the nearest potential receptor is about a 300 m away) would experience an elevated exposure risk based on USEPA's exposure assessment guidelines. Therefore, the impacts associated with HAP emissions would be negligible.

BLM Colorado's approach for assessing climate impacts in NEPA has been to use the decision scope emissions as a surrogate (or proxy) for describing the known (modeled) climate impacts associated with the various global emissions scenarios. This approach has been adopted specifically because there are presently no climate analysis tools or techniques that lend themselves to describing any actual climate or earth system response (such as changes to sea level, average surface temperatures, or regional precipitation rates) that would be attributable to the quantized emissions associated with any single action, decision, or scope. The degree to which any observable changes to biotic and abiotic systems resulting from climate change would be attributable to the New Elk Mine's operations cannot be reasonably stated at this time. However, contrasting the proxy emissions at various scales relative to a quantity of emissions analyzed to have a definitive climate impact allows BLM to provide a relative sense for the intensity of the proxy emissions.

Climate change is fundamentally a cumulative issue with global scope, and all GHGs contribute incrementally to climate change, regardless of the emission's location, duration, or source type. Given the cumulative nature of GHGs and the climate change issue, and a lack of Project-specific impacts, we are presenting a complete emissions analysis and a description of anticipated changes and impacts from climate change in the cumulative impacts section below.

Over the projected 30 year life-of-the-project, the No Action Alternative mining activities will contribute 257.42 million metric tons of GHGs to the atmosphere on a CO_2e basis.

1.3.2 Proposed Action Alternative

All of the effect of mining, processing, transport, and coking of coal described for the No Action Alternative would occur under the Proposed Action Alternative. The Proposed Action would have the practical effect of extending the mine's life by an additional 5 years due to the availability of the federal coal. Based on the mine plan shown and described above, it is not likely that mining federal coal would begin during the first few years after mine operations resume. Mining the federal coal is not expected to alter how New Elk would maintain operations; therefore, emissions can be expected to remain at the rates shown above for the No Action Alternative. Similarly, the impacts of the emissions from operational activities would be the same as the No Action Alternative.

However, the additional federal coal made available under the approval of the Proposed Action would amount to additional GHG loading of the atmosphere. At projected mining rates, the total direct and indirect GHG emissions from 5 additional years of mining under the Proposed Action would contribute an additional 42.9 million metric tons of GHG on a CO_2e basis.

1.4 Cumulative Actions and Effects

The cumulative impact assessment for air quality considers air emissions from mine operations and coal transport when added to other past, present, and reasonably foreseeable future actions. Except for the additional GHG loading, the affects described in this section are applicable to both the No Action and Proposed Action Alternatives.

To examine potential cumulative air quality impacts from activities that it authorizes, BLM initiated the CARMMS (BLM 2017). The study version 2.0 was primarily concerned with assessing statewide impacts of projected oil and gas development (both federal and fee [i.e., private]) out to year 2025 for three development scenarios (low, medium, and high). Projections for development are based on either the most recent Reasonably Foreseeable Development (RFD) document (high), or a projection of the current 5-year average development pace forward to 2025 (low). The medium scenario includes the same well count projections as the high scenario, but assumes restricted emissions, whereas the high and low scenarios both assume current development practices and existing emissions controls required by regulations.

For coal resources, the study provided a mining scenario based on each mine's maximum allowable emissions rate, which were estimated based on the CDPHE APEN database and available Environmental Impact Statements (EISs) and Environmental Assessments (EAs) prepared for previous authorizations. Readers should be aware that most mines in Colorado are not currently producing at their maximum (i.e., what CARMMS analyzed) authorized capacities. The primary difference between the low and high scenario was an assumption about the number of potential new mines (hypothetical, including New Elk) that could come online, and how existing mines might not be operational in the future model year. Regardless, it is apparent that CARMMS modeled plenty of emissions, as shown in **Table 12**.

Table 12 CARMMS High Scenario Source Apportionment Emissions (tpy)

SA Area	PM_{10}	$PM_{2.5}$	VOC	NO_X	CO	SO_2
RGFO #4	96.86	18.69	504.89	132.38	237.13	0.16
CO Mines	4,146	1,148	37	3,297	NA	18

Because the Comprehensive Air Quality Model with Extensions (CAMx) is a one-atmospheric dispersion model, it requires emissions inventories to be modeled accurately at both spatial and temporal scales. This fact allowed the BLM to leverage the study and apply the source apportionment technology to all the emissions from coal mines in Colorado that produce federal coal. Unfortunately, BLM did not have the resources to track each mine independently, as was done for each Field Office's oil and gas development (which was the primary purpose of the CARMMS model), but rather, all the mines were tracked together as a single source group. Source apportionment applicable to the source group included the following existing and hypothetical mines:

- Book Cliffs Area (Grand Junction)
- McClane (Grand Junction)
- Bowie (Uncompahgre)
- King II (Tres Rios)
- Foidel (Kremmling)
- Deserado (White River)

- Trapper (Little Snake)
- Colowyo (Little Snake)
- Sage Creek (Little Snake)
- West Elk (Uncompahgre)
- Elk Creek (Uncompahgre).
- New Elk (Royal Gorge).

Although the predicted impacts are based on a future model year emission (2025), the differences in the impacts between the scenarios and the base year provide insight into how mass emission changes impact the atmosphere on a relative basis and are thus useful for making qualitative and quantitative comparisons with emissions levels at the current pace of development. For the Royal Gorge Field Office (RGFO), we are disclosing the high CARMMS scenario to account for all the reasonably foreseeable future actions that could occur within the area that are mostly a result of projected oil and gas development. Further, the RGFO is continuing to study sub-areas (specifically Area 4) to provide more detailed source apportionment results that would be more closely associated to what could be expected from New Elk Mine (on a relative emissions basis). The effects are representative of both the No Action and Proposed Action Alternatives.

1.4.1 BLM Planning Areas

Figure 3 presents the mining model results and shows that PM emission impacts are primarily the result of surface mining facilities in the northern portion of the CARMMS analysis domain. In general, primary PM (the kind the mines emit) is a localized pollutant. The 4 km grid resolution of the model is less sensitive to settling and terrain impacts (i.e., plume depletion) for primary PM than a nearfield model would show. Although the PM concentrations are a bit high due to the model resolution, they are reasonable across the larger domain. The PM contributions from all the mines appears to be low around the New Elk facility (not more than 4µg/m^3 for PM_{10} and 0.4µg/m^3 for $PM_{2.5}$). The other pollutants (NO_2 and O_3) are also equally minor impactors, although we note that the O_3 predictions are a function of the mine's direct NO_x and VOC contributions and do not include any potential CMM VOCs because they are unknown.

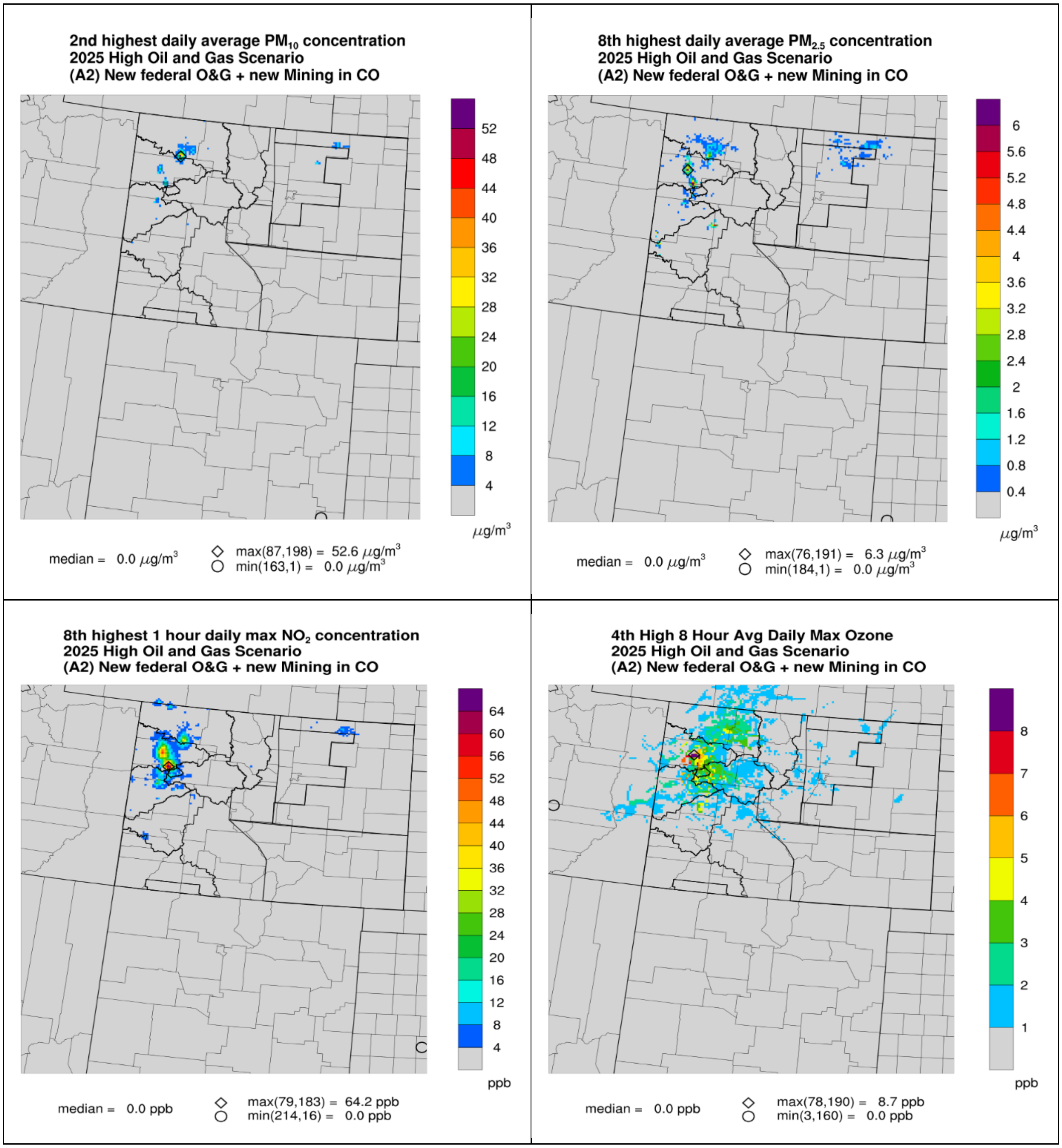

Figure 3 Contribution to the 2025 High Scenario Mining from Federal Coal Producing Mines (R)

Figure 4 shows that the RGFO #4 source apportionment impacts are also relatively minor and are mostly the result of development in and proximate to the Raton Basin (coalbed methane). The New Elk Mine has a comparable emissions profile (except for VOC) to that of the high oil and gas scenario, such that the impacts from the mine itself would also be of a similar nature. With fewer NO_X and VOC emissions than those of the high oil and gas scenario, the mine is not expected to contribute significantly to direct O_3

formation. The AQRV data metrics in **Table 13** show that the Colorado Mines (particularly, the surface mines) contribute greatly to the PM-related NAAQS and visibility impacts, although they also appear to be highly localized. Although the exact New Elk Mine contributions cannot be teased out of the data, it is highly unlikely that the mines emissions contribute a significant fraction of the modeled AQRV impacts. The mine most likely has impacts similar to those of the RGFO #4 results solely based on the relative emissions levels and spatial proximity of the mine to the oil and gas sources.

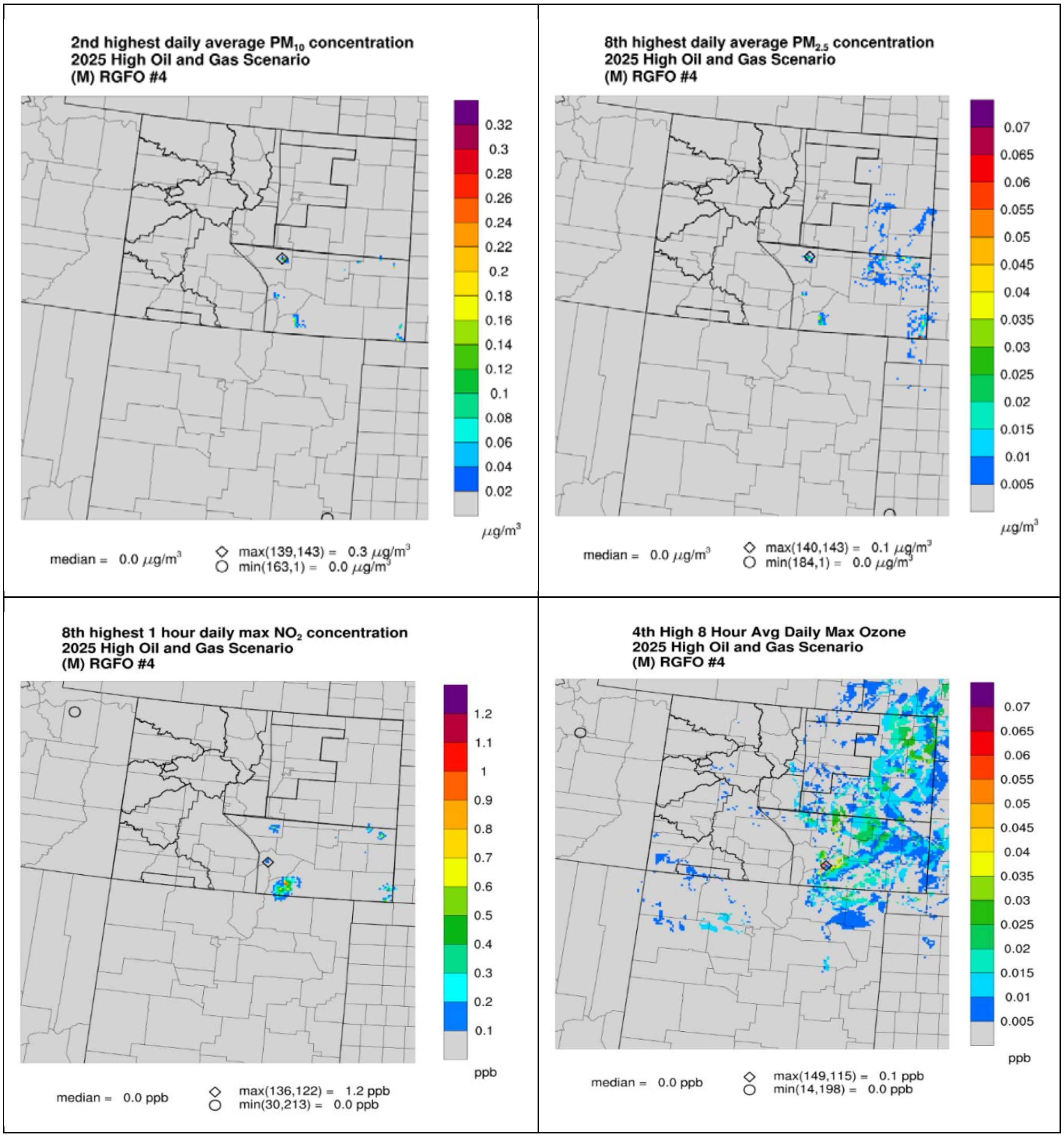

Figure 4 **Contribution to the 2025 High Scenario (M) Royal Gorge Field Office #4**

Table 13 Maximum Source Group Contributions Mines and RGFO #4 High Oil and Gas Scenarios (R and M)

<table>
<tr><th rowspan="2">Source Group</th><th colspan="3">Visibility Impacts</th><th>Deposition</th><th>AQRV</th><th colspan="2">Max Contribution to Exceedance</th></tr>
<tr><th>Max dv</th><th>Days > 0.5dv</th><th>Days > 1.0dv</th><th>(kgN/ha yr)</th><th>Impacted Area</th><th>O_3 (ppb)</th><th>$PM_{2.5}$ (ug/m^3)</th></tr>
<tr><td>CO Mines (Class I Area)</td><td>0.6034</td><td>1</td><td>0</td><td>0.0581</td><td>Flat Tops</td><td rowspan="2">0.2071</td><td rowspan="2">0.0287</td></tr>
<tr><td>CO Mines (Class II Area)</td><td>0.6442</td><td>2</td><td>0</td><td>0.1730</td><td>Dinosaur NM</td></tr>
<tr><td>RGFO #4 O&G (Class I Area)</td><td>0.0079</td><td>0</td><td>0</td><td>0.0005</td><td>Pecos/Great Sand Dunes</td><td rowspan="2">0.0258</td><td rowspan="2">0.0013</td></tr>
<tr><td>RGFO #4 O&G (Class II Area)</td><td>0.0157</td><td>0</td><td>0</td><td>0.0025</td><td>Spanish Peaks</td></tr>
</table>

For the total cumulative results (rolled up source apportionment and total model outputs), the BLM is disclosing the high CARMMS scenario.

As shown on **Figure 5**, the surface mines are driving the estimated PM impacts within the CARMMS model from all the federal emissions. We also note that the impacts represent the maximum contributions recorded (in the form of the applicable standard) but note that these maximums are not necessarily relative to any exceedance values that may have been modeled for a pollutant.

The plots on **Figure 6** and **Figure 7** above show the maximum modeled concentrations and the expected changes from future emissions relative to the base year. As can be seen, most of the analysis area sees relatively modest decreases or no changes to O_3 formation potential. Particulate matter impacts are mostly confined to the urban areas in Colorado and can be attributed to the expected population increases projected to occur (which have occurred steadily since the CARMMS base year). Interestingly, these areas also project some of the largest drops (undoubtably due to tighter mobile source standards). Another interesting model artifact is the high O_3 predicted along the I-70 corridor north of the proposed Project Area. This region has always been a “hot spot” for the CAMx and Community Multiscale Air Quality Modeling (CMAQ) photochemical models (even in the updated Intermountain West Data Warehouse 2011b platform) for reasons currently unknown. We suspect that the area’s topography, especially the rapid elevation gains along the Roan Cliffs, along with the limits of the CAMx and Weather Research and Forecasting (WRF) meteorological model resolutions may be at least partially responsible. Ultimately, it has been shown that the model tends to over-predict O_3 in western Colorado. Thus, the O_3 results on face value should be considered conservative. Overall, the CARMMS data suggest that air quality impacts surrounding the mine are essentially negligible.

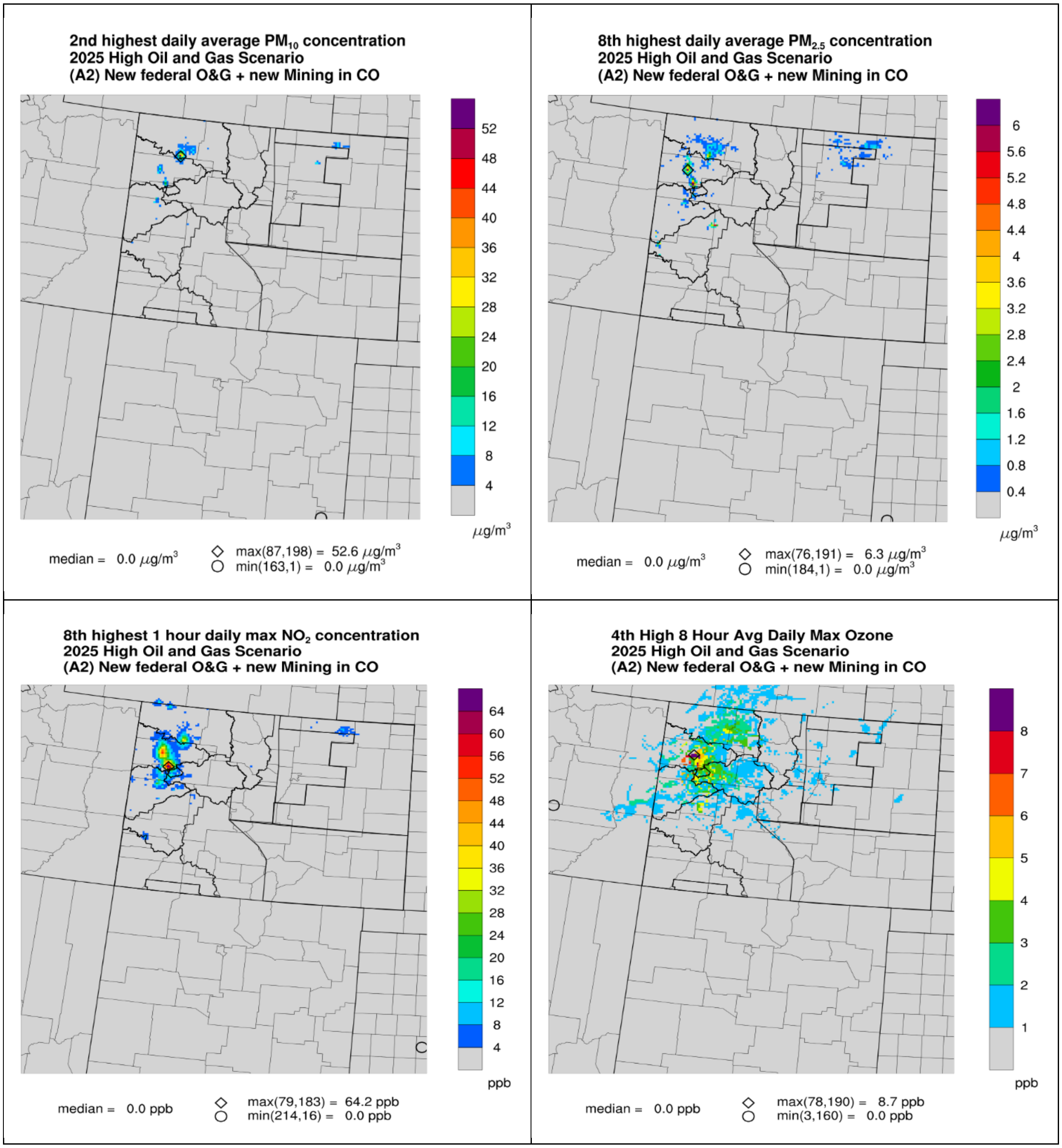

Figure 5 Contribution to the 2025 High Scenario (A2) New Federal O&G and Mining

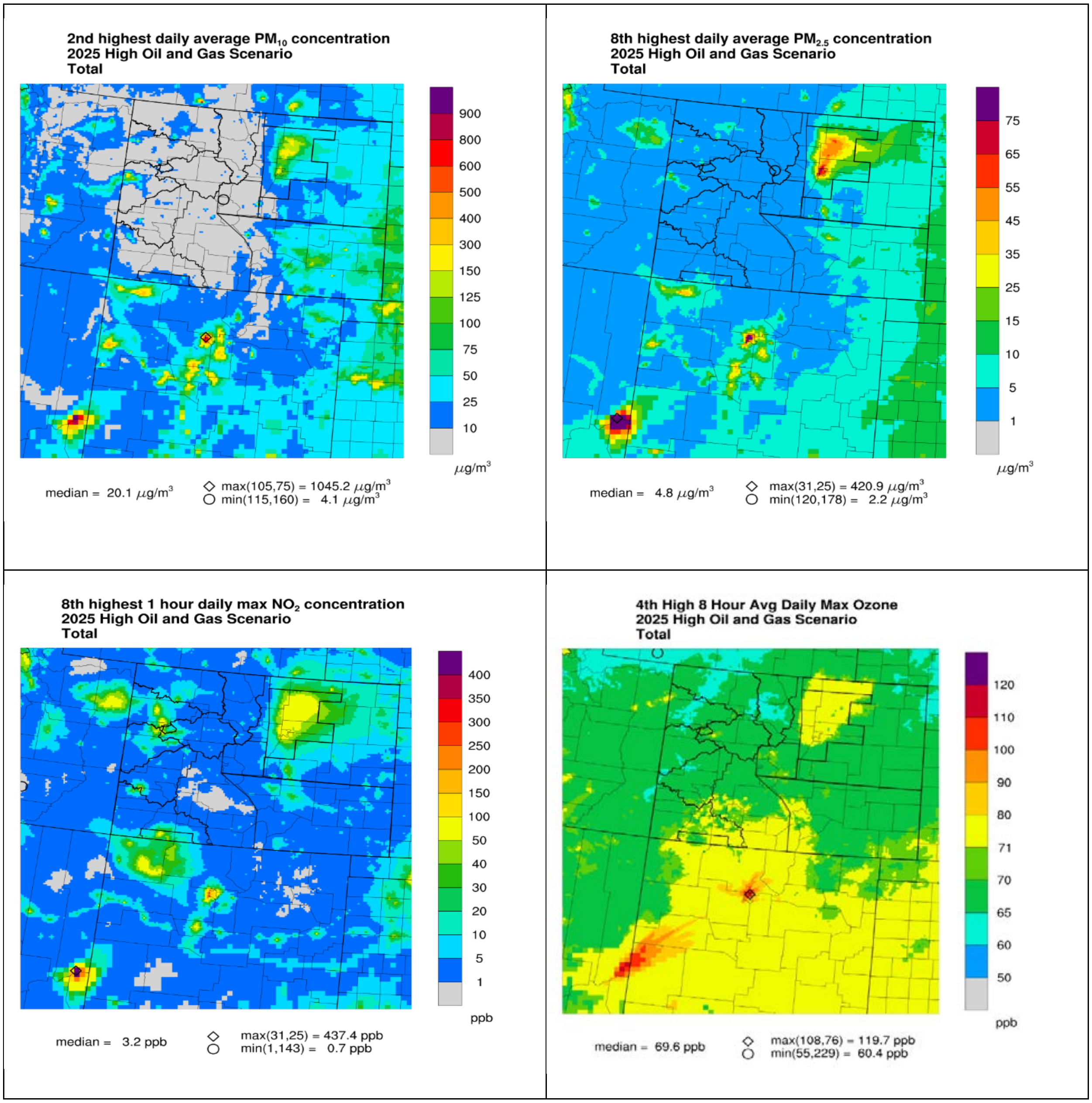

Figure 6 Total Cumulative Impacts to the 2025 High Scenario (Environ 2017)

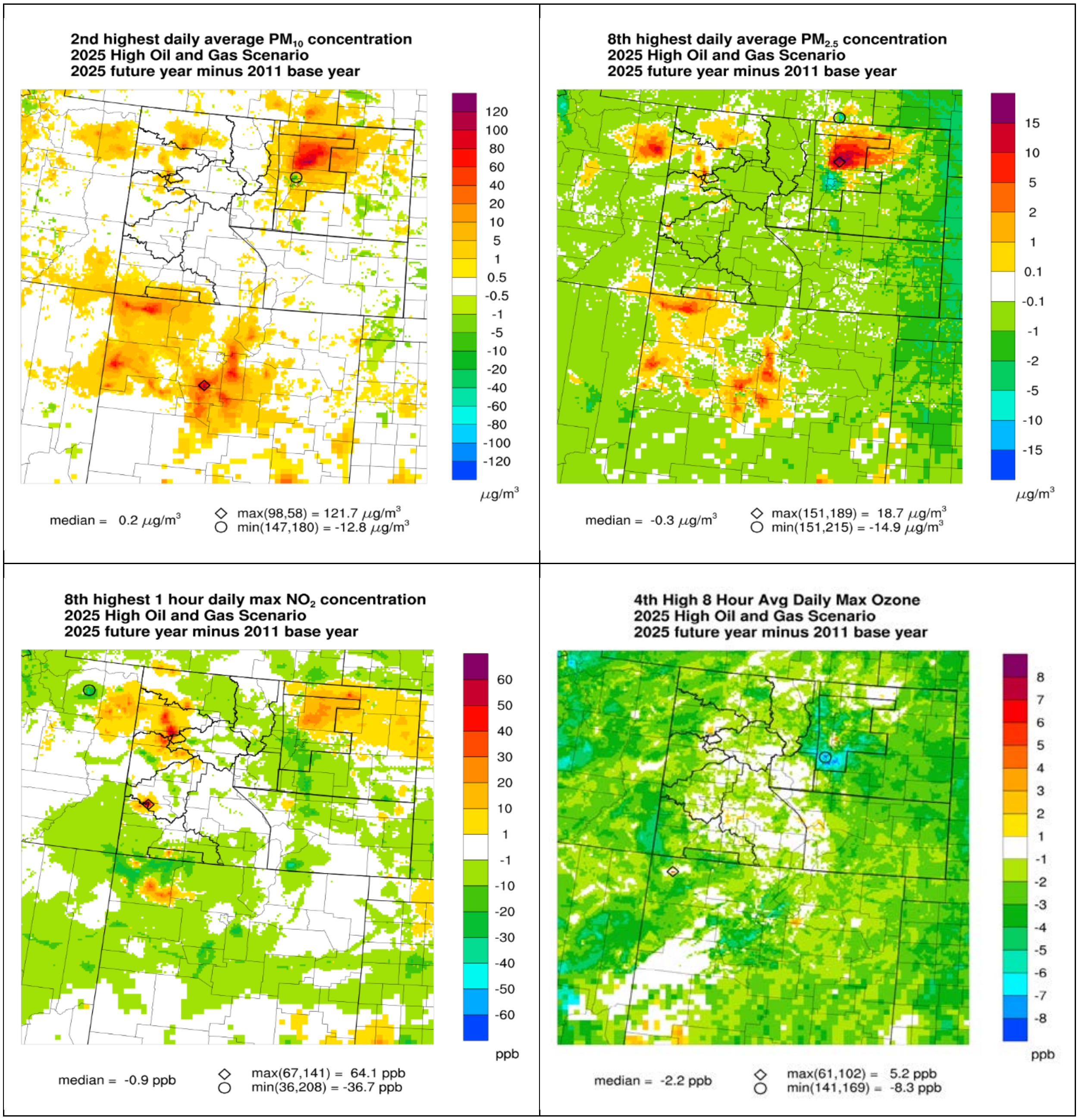

Figure 7 Cumulative Changes (future minus base) High Scenario (Environ 2017)

Table 14 shows the cumulative AQRV impacts from the combined sources groups cited on **Figure 6** and **Figure 7**. Cumulative AQRV thresholds for analysis do not exist for the AQRVs presented, although it is obvious that they exceed the project level thresholds at the maximum impacted areas.

Table 14 Maximum Source Group Contributions Mines + High Oil and Gas Scenario (A2)

Source Group	Visibility Impacts			Deposition	AQRV	Max Contribution to Exceedance	
	Max dv	Days > 0.5dv	Days > 1.0dv	(kgN/ha yr)	Impacted Area	O_3 (ppb)	$PM_{2.5}$ (ug/m^3)
CO O&G and Mines (federal) (A2) Class I	1.60	50	5	0.0124	Dinosaur NM	4.6	0.0287
CO O&G and Mines (federal) (A2) Class II	2.63	103	37	0.0065	Dinosaur NM	4.6	0.0287

1.4.1.1 Greenhouse Gas Emissions Analysis

Climate change is fundamentally a cumulative issue with global scope, and all GHGs contribute incrementally to climate change regardless of the emission's location, duration, or source type. The multitude of interwoven natural systems and feedback mechanisms that contribute to climate variability over the entirety of the Earth makes analysis of this issue exceptionally complex. Climate scientists provide for analysis by modeling changes to these systems in response to a range of global emissions scenarios known as Representative Concentration Pathways (RCPs). RCPs are not fully integrated scenarios of climate feedback, policy, emissions limits, thresholds, or socioeconomic projections, but rather a consistent set of cumulative emissions projections (out to year 2100) of only the components of RF that are meant to serve as input for climate and atmospheric chemistry modeling. There are four primary pathways that climate scientists have used for assessment in numerous climate models; they are as follows:

RCP2.6 - Very low emissions levels leading to peak in RF at 3.1 W/m^2 by mid-century, returning to 2.6 W/m^2 by 2100, where GHG emissions (and indirectly emissions of air pollutants) are reduced substantially over time. This pathway provides for an abrupt and rapid decline in CO_2 emissions starting around 2020, with atmospheric concentrations of GHGs and subsequent RF stabilizing between 2040 and 2060. This scenario also provides for "negative emissions" starting in 2080, and essentially projects that more carbon is removed from the atmosphere than is emitted. The curve suggests that emissions from fossil fuels and other sources would decline by approximately 3.5% per year until 2040, and then continue at a pace of approximately 10% per year until the emissions become negative between 2070 and 2080. The cumulative emissions of this pathway are approximately 1,715.7 gigatons of carbon dioxide equivalent ($GtCO_2e$; 2018 through 2100). CO_2 alone represents 54.2% of the total contributing emissions, and 81.5% of the total CO_2 emissions are attributable to fossil fuel use.

RCP4.5 - Stabilization scenario where total RF is stabilized at 4.5 W/m^2 before 2100 by employment of a range of technologies and strategies for reducing GHG emissions. This pathway forecasts that global emissions will increase until about 2040, with actual stabilization occurring between 2030 and 2050. Starting in 2050, emissions would start to decline at rates commensurate with the 2.6 pathway until 2080, when emissions stabilize again through the end of the century. GHG concentrations and forcing would continue to rise through the end of the century, although the rate of increase diminishes significantly around 2070. Emissions of both CH_4 and N_2O are flat throughout the century and do not contribute significantly to additional RF. The cumulative emissions of this pathway are approximately 3,728.6

$GtCO_2e$ (2018 through 2100). CO_2 alone represents 67% of the total contributing emissions, and 98.2% of the total CO_2 emissions are attributable to fossil fuel use.

RCP6.0 **-** Stabilization without overshoot pathway with RF of 6 W/m^2 after 2100 by employment of a range of technologies and strategies for reducing GHG emissions. Emissions of both CH_4 and N_2O are more or less stable throughout the century and do not contribute significantly to additional RF, while emissions of CO_2 grow steadily until 2080 before declining. The cumulative emissions of this pathway are approximately 5,380.2 $GtCO_2e$ (2018 through 2100). CO_2 alone represents 74.3% of the total contributing emissions, and 101.1% of the total CO_2 emissions are attributable to fossil fuel use. Please note, the Land Use Change (LUC) CO_2 emissions in this scenario are negative at about the mid-century mark, which produces data showing fossil fuel emissions that are greater than the total emissions (which include the negative LUC values).

RCP8.5 **-** Increasing emissions over time leading to very high GHG concentration levels and RF of 8.5 W/m^2 in 2100. This pathway assumes that emissions trajectories follow a historical growth curve and is representative of the high range of non-climate policy scenarios or a worst-case scenario that assumes unabated emissions. The cumulative emissions of this pathway are approximately 9,227.7 $GtCO_2e$ (2018 through 2100). CO_2 alone represents 72.3% of the total contributing emissions, and 97.8% of the total CO_2 emissions are attributable to fossil fuel use. Given the recent and ongoing developments occurring globally including market forces that are driving demand for sustainable energy solutions, public policy advancements such as the Paris Agreement, and the continuous communication of the issue, it is unlikely that this pathway would come to pass over the course of the remainder of the century.

Figure 8 and **Figure 9** below show the carbon loading levels of each RCP scenario and the anticipated concentrations of accumulating CO_2 in the atmosphere.

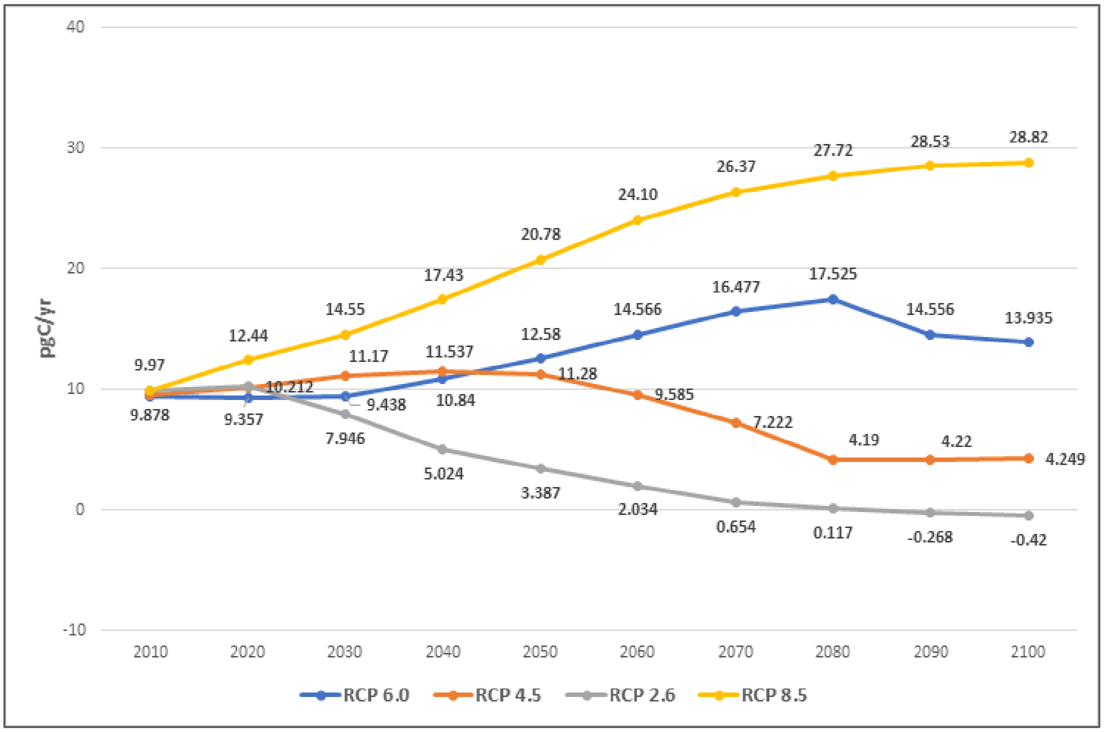

Figure 8 **Global GHG Emissions Projections**

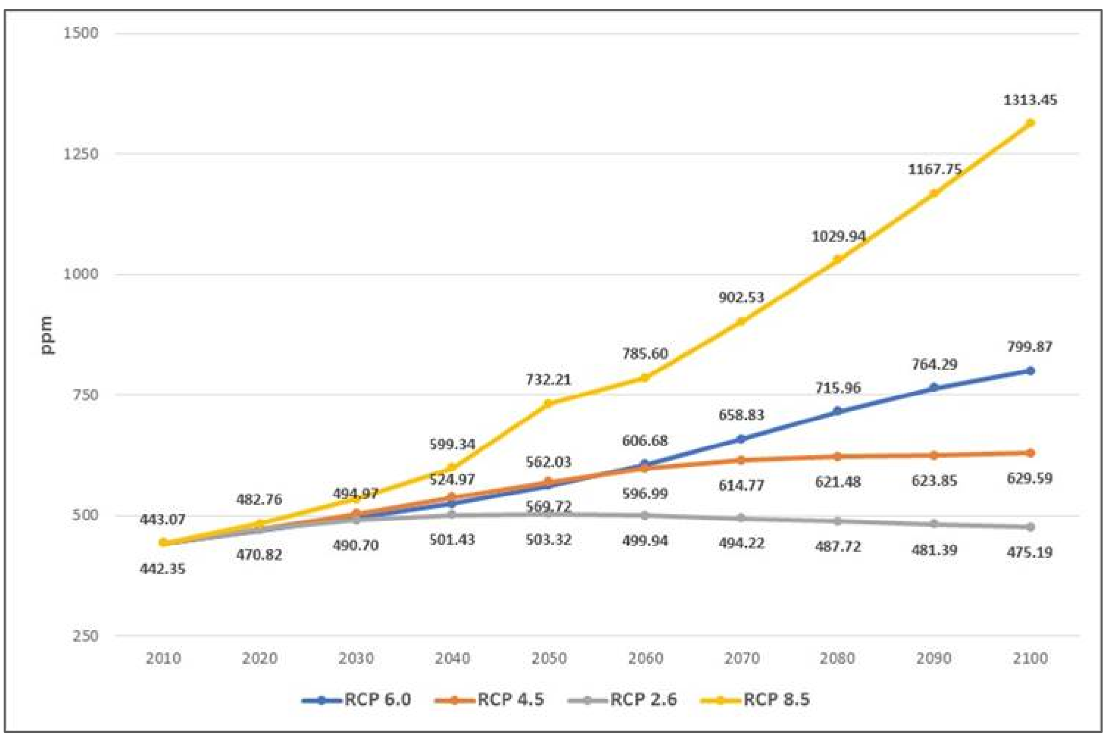

Figure 9 **CO_2e Atmospheric Concentration Projections**

1.4.1.2 The Carbon Budget

A growing body of analysis on coupled climate-carbon models has shown that temperature is closely related to the total amount of CO_2 emissions released over time, where the cumulative emissions (i.e., the area under the curve), rather than the timing or shape of the emissions curve, is more important for peak warming estimates. This also means that mitigation requirements can be quantified using a budget approach, or the amount of CO_2 emissions that can still be emitted (cumulatively) relative to a target temperature (global mean temperature increase) with varying degrees of probability that such a budget will limit warming to not more than the target. In general, the world has come to the consensus that limiting warming to 1.5°C or less than 2°C can avoid some of more dire consequences associated with projected climate change. A tremendous amount of effort has been put forth by the climate science community to estimate a bright-line budget consistent with the consensus temperature targets. The budget has evolved over time as scientists refine data and estimates of cumulative carbon emissions that have already occurred. For example, scientists recently revised the budget as described in the IPCC Special Report to account for problems associated with the Earth System Models used in the AR5 budget estimates. These models underestimated historical cumulative CO_2 emissions and were projecting temperatures warmer than have been observed. The new estimates rely on observational constraints to make the budget calculations, which have been widely accepted by climate scientists as being more accurate.

The newest budget estimates are expressed as the remaining cumulative CO_2 emissions from the start of 2018 until the time of net zero global emissions, and suggest a value of approximately 420 $GtCO_2$ for a two-thirds chance of limiting warming to 1.5°C, and about 580 $GtCO_2$ for an even chance (50/50). However, the estimates contain uncertainties that are characteristic of scientists’ current understanding of Earth's climate influencing systems, such as feedbacks and the forcing and response associated with the non-CO_2 GHG species. The uncertainty range associated with the new estimate is ±400 $GtCO_2$. The large uncertainty range (relative to the target budget) illustrates the difficulty of climate analysis. These uncertainties are more important to the probability of success for a given budget estimate the closer warming is observed to the target limit. As such, it is likely that the absolute budget targets, or at the very least, the estimated remaining time until emissions are required to reach carbon neutrality or net zero, is likely to change over time as emissions trajectories fluctuate and climate science evolves. In the most basic terms, the uncertainty suggests that emissions need to start declining in the next decade to maintain reasonable progress. Staying within the remaining carbon budget of 420 $GtCO_2$ implies that CO_2 emissions reach net zero in about 20 years, or 30 years for a 580 $GtCO_2$ budget. Additionally, the neutrality timelines assume an emissions trajectory following newly devised 1.5 pathways, which limits cumulative GHGs to a higher degree than pledges made under the Paris Agreement afford. The 1.5 pathways have a global 2030 emissions target of approximately 25 to 30 $GtCO_2$ in contrast to the Paris Agreement 2030 targets of 52 to 58 $GtCO_2$ per year. Some of the latest research suggests that interim warming would exceed or overshoot the temperature targets before the end of the century. In these scenarios, the models assume negative emissions (sequestration) after net zero to regain the temperature target by 2100. The majority of these scenarios also employ uncertain technologies, known as Carbon Dioxide Removal (CDR) measures, to neutralize emissions from sources for which no known mitigation measures have been identified. Deploying CDR at scale is unproven, and reliance on such technology represents major risks; however, CDR is needed less in mitigation scenarios with a particularly strong emphasis on energy efficiency and low demand for carbon-based fuels.

Despite global awareness and acknowledgement of the climate change issue, emissions rates around the world continue to rise and are projected to continue doing so under most pathway scenarios in the short term. Modernization, population growth, and standard of living advances have all contributed to increased energy demand and LUCs that on balance have led to higher emissions year after year. According to the Global Carbon Project, cumulative CO_2 emissions from fossil fuels were estimated to have reached 37.1 Gt in 2018 (**Figure 10**). This value is equivalent to 9.83 petagrams of carbon (PgC), and most closely approximates the RCP4.5 scenario relative to the 2020 emissions year. At current emissions rates, the average face value of the budget (500 $GtCO_2$) would be exhausted in approximately 13.48 years. Relative to the mean 2030 emissions budget target, existing global emissions would need to drop by approximately 26% over the next decade to maintain reasonable progress. Recent data from the USEPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks and estimates of U.S. emissions from the Global Carbon Project show that, on average, the U.S. emits 14.2% of the global fossil fuel CO_2 emissions annually (since 2015). In terms of the carbon budget, the annual U.S. emissions are equal to approximately just more than 1% of the average face value (BLM 2019).

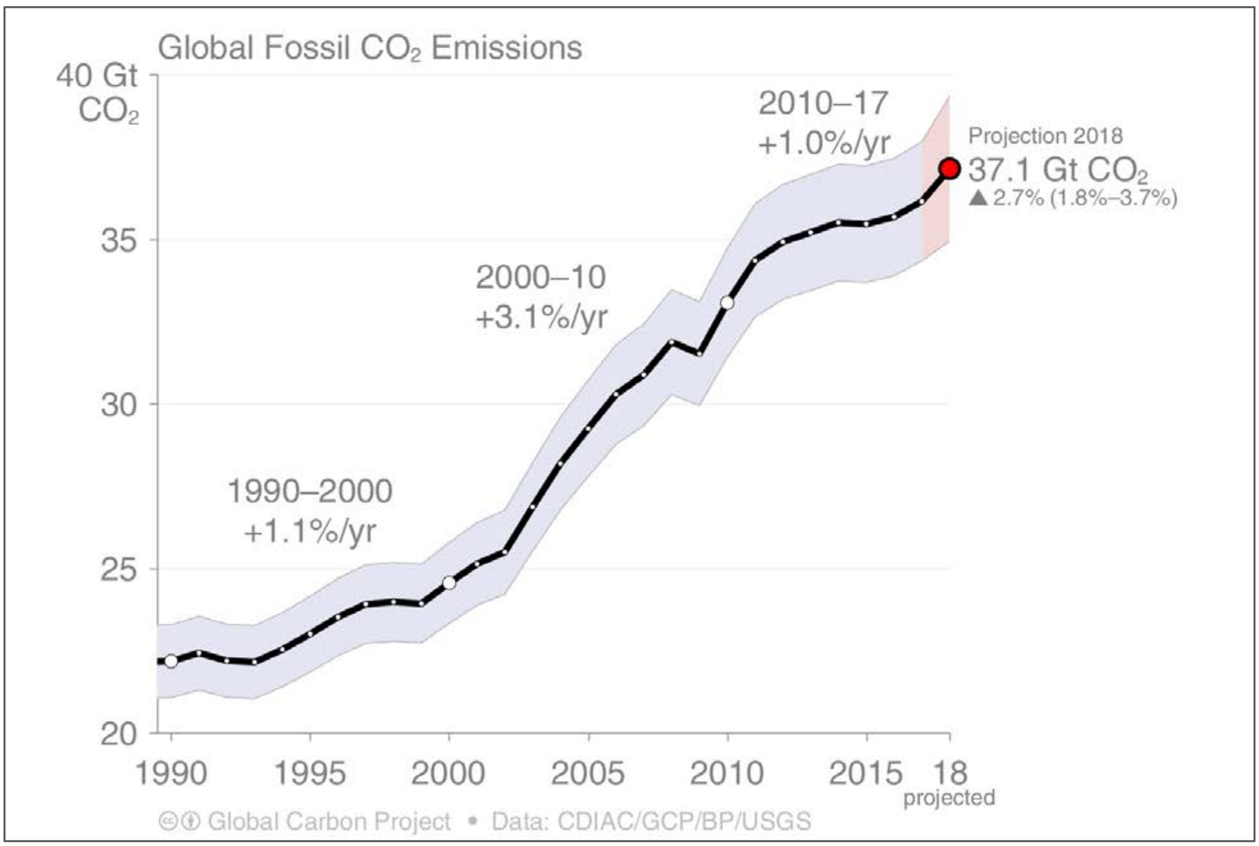

Figure 10 Carbon Emissions Trends

According to the Energy Information Administration (EIA), domestic energy production accounts for about 90% of all U.S. energy consumption. The three major fossil fuels — petroleum (28%), natural gas (31.8%), and coal (17.8%) — combined accounted for about 77.6% of this production, while renewable energy sources (12.7%) and nuclear electric power (9.6%) provide the remainder. The EIA's Annual Energy Outlook (AEO) report provides modeled projections of domestic energy markets through 2050, and includes cases with different assumptions regarding macroeconomic growth, world oil prices, technological progress, and energy policies. In general, the last few years of baseline reference case data have shown strong domestic production coupled with relatively flat energy demand. The reference case estimates that natural gas consumption will grow the most on an absolute basis (0.8% annually), and nonhydroelectric renewables will grow the most on a percentage basis. Petroleum and coal annual growth is projected to be negative over the projection period, at -0.3% and -0.2%, respectively. The outlook suggests that the U.S. could become a net energy exporter over the projection period in most cases. The report is produced using the National Energy Modeling System (NEMS), which is capable of capturing interactions of economic changes and energy supply, demand, and prices. However, the report comes with caveats that data users need to consider. First, the projections are not predictions of what will happen, but rather forecasts of what may happen given certain assumptions and methodologies. Second, energy market projections and many of the events that shape free energy markets (such as future developments in technologies, demographics, available resources, and resource constraints) cannot be reasonably foreseen, and are therefore subject to high uncertainty.

Domestic energy supplies of fossil fuel minerals can be generally classified as either federal or other, where other signifies either state, local, private citizen, or corporate ownership. The BLM manages the onshore federal mineral estate, on behalf of the public and in accordance with numerous laws, regulations, and policies, to provide for the nation’s energy security and to enable free energy markets to function in order to meet domestic energy demands. BLM Colorado uses data from the Office of Natural Resources Revenue (ONRR), which provides production accounting services for all domestic fossil fuel minerals and allows the BLM to understand the nation’s downstream carbon footprint (assuming combustion) based on the current domestic energy production/supply mix. The available ONRR data for fossil fuel production in the U.S. and Colorado (federal only) are shown in **Table 15**. The coal production data from ONRR were supplemented with data available from the Colorado Division of Mine Reclamation and Safety (CDRMS). The table also provides BLM's estimate of each fuel's GHG contribution and the percent of the carbon budget increment the fuel's CO_2 emissions would represent on an annualized basis.

The data in **Table 15** show that consuming all of the federal energy produced in the U.S. in 2017 (onshore and offshore) would be equivalent to 0.27% of the remaining carbon budget, while the Colorado component of the federal mineral estate is approximately 0.01% of the carbon budget and just 1.12% of total U.S. fossil fuel energy emissions (CO_2e) annually. At the current production rates shown, total federal mineral combustion would exhaust the carbon budget in approximately 372 years, while federal minerals in Colorado would do the same in about 8,776 years. These timelines show a stark contrast relative to the current global emissions track. The data also illustrate why coupled carbon is an appropriate metric for establishing a target-based emissions budget, in that relative to the CO_2e estimates, CO_2 emissions from fossil fuel combustion clearly have an outsized effect on potential forcing (CO_2 is 99.9%+ of CO_2e). Consequently, BLM Colorado is limiting further downstream combustion estimates to CO_2 only for the remainder of this report.

Table 15 2017 Total U.S. and Federal Fossil Fuel Emissions

Fuel (scope)	Production (units)	% Total	% Federal	CO_2	CH_4	N_2O	CO_2e	% Carbon Budget
U.S. Natural Gas (Total)	33,177,826,000 (thousand cubic feet [Mcf])	100	NA	1,806.20	0.03	0.00	1,808.42	0.36124
U.S. Natural Gas (Federal)	4,327,941,937 (Mcf)	13.04	100	235.61	0.00	0.00	235.9	0.04712
Colorado Natural Gas (Federal)	650,286,607 (Mcf)	1.96	15.03	35.40	0.00	0.00	35.45	0.00708
U.S. Petroleum (Total)	3,418,954,000 (barrels of oil [bbls])	100	NA	1,477.6	0.06	0.01	1,483.15	0.29552
U.S. Petroleum (Federal)	811,690,488 (bbls)	23.74	100	350.8	0.01	0.00	352.11	0.07016
Colorado Petroleum (Federal)	5,203,706 (bbls)	0.15	0.64	2.25	0.00	0.00	2.26	0.00045
U.S. Coal (Total)	*772,066,368 (tons)	100	NA	1,795.05	0.21	0.03	1,811.87	0.35901
U.S. Coal (Federal)	326,073,802 (tons)	42.23	100	758.12	0.09	0.01	765.22	0.15162
Colorado Coal (Federal)	8,310,231 (tons)	1.08	2.55	19.32	0.00	0.00	19.50	0.00386

Notes:
Emissions units are million metric tons (MMT). Estimates are based on USEPA emissions factors. *Coal estimated as 6% growth from 2016 data (source: EIA 2016). Data assume 50% federal DRMS production for federal mines with no ONRR documentation. % Carbon Budget (CB) calculated for mean face value of 500 $GtCO_2e$.

Over the life of the project, the mine is estimated to contribute 300.3 million tons of CO_2e (direct and indirect) if all of the recoverable coal is mined under the Proposed Action. The federal scope or portion of that estimate would be 14.3% or 42.9 million tons of CO_2e (Proposed Action minus the No Action). Although not strictly a one to one comparison, on a CO_2e basis, the No Action Alternative would consume approximately 0.06% of the remaining carbon budget, while the federal scope of the Proposed Action Alternative would consume 0.01%.

To provide a full cumulative context for a carbon budget analysis, the BLM is projecting all of the reasonably foreseeable direct and indirect GHGs associated with the CARMMS scenarios (low and high) forward to two specific future years. The study analyzed linear rates of oil, gas, and coal exploration and development (upstream) over a 10-year period, which allowed for the annual average rates of emissions from the associated activities to be extracted and used in the projection calculations. Indirect downstream emissions (from product end use) are calculated for the same projection periods by applying USEPA combustion emissions factors to the cumulative production estimates for each scenario. Projected production estimates are derived by applying the annualized AEO reference case growth rates for each mineral resource to the current resource production values obtained from ONRR. For the low scenario, the result should be consistent with the development projections made for CARMMS, which assumed an average development rate based on 5 years of historical data and captures recent technology advancements and current laws and regulations, similar to the AEO's reference case scenario. For the high scenario, the production estimates require an additional scaling factor based on the ratio of development between the low and high scenario such that BLM can account for the additional production that would be associated with higher annual average rates of oil and gas development. Coal production in CARMMS was held static across all scenarios for operational mines; therefore, no additional scaling is required. The first projection period is being made for 2018 to 2032, and is designed to approximate a no growth, no reduction emissions scenario where the carbon budget is consumed in 14 years (based on current global emissions rates). The second projection period assumes steep global emission declines to net zero in 2050, and also assumes that the entire budget is consumed. The data for the projections are shown in **Table 16**.

Table 16 BLM Colorado (Federal) Projected Carbon Budget Consumption

Scenario	% Carbon Budget (2018 2032)	% Carbon Budget (2018 2050)
Low Oil and Gas - Upstream	0.01	0.03
Low Oil and Gas - Downstream	0.12	0.28
Low Coal - Upstream	0.01	0.01
Low Coal - Downstream	0.06	0.12
Total Low	0.20	0.44
High Oil and Gas - Upstream	0.02	0.05
High Oil and Gas - Downstream	0.22	0.53
High Coal - Upstream	0.01	0.03
High Coal - Downstream	0.06	0.12
Total High	0.31	0.73

Notes:

% Carbon Budget (CB) calculated for mean face value (500 Gt)

BLM Colorado is also providing estimates of the total cumulative federal decision scope emissions based on the methods described above. Projections for new oil, gas, and coal development in other states are unknown, and the emissions development strategies employed for CARMMS that are specific to Colorado's regulatory structure and the development parameters within each of the state's basins would be inappropriate to apply to the national scope. In order to estimate the upstream portion of the national emissions scope, the BLM is using published Life Cycle Assessment (LCA) data for energy use within the power sector as a reasonable surrogate for back-calculating these emissions as a percentage of the totals relative to the projected downstream percentages. The LCA data show that production, processing, and transport emissions account for approximately 5% of the total life-cycle emissions for coal-fired power generation and 15% of the total lifecycle emissions for natural-gas-fired power generation (assumed to be similar for oil lifecycle).

At the AEO growth rates, total federal upstream and downstream emissions of CO_2 from oil, gas, and coal are estimated to be 5.91, 4.01, and 11.19 Gt, respectively, for the 2032 projection period. For the 2050 projection scenario, these emissions are estimated to be 12.65, 8.59, and 25.39 Gt. As previously stated, the BLM has management responsibilities (decision scope authority) for onshore federal minerals only. According to ONRR, in 2017, onshore federal production accounted for 74.3% of all natural gas produced and 31.2% of all oil production (coal production is obviously 100% onshore). Applying the onshore percentages to the projected emissions scenarios shows BLM's potential decision scope of approximately

3.32% to 7.15% of the carbon budget. Projecting total domestic demand for fossil fuels (federal, non-federal, domestic, and imported) forward by the methods outlined above shows that, as a nation, the U.S. could consume 16.7% to 35.9% of the carbon budget. Relative to the domestic demand projections, federal mineral emissions would account for approximately 20% of the national budget consumption estimates.

1.4.1.3 Projected Climate Change

The future climate equilibrium is dependent upon warming caused by past anthropogenic emissions, future anthropogenic emissions, and natural variability. The following information on predicted climate change has been summarized from the IPCC Summary to Policymakers (IPCC 2014).

Global mean surface temperature change for the period 2016–2035 relative to 1986–2005 is similar for the four RCPs and will likely be in the range of 0.3°C to 0.7°C (medium confidence). The projection assumes no major volcanic eruptions, changes in natural emissions sources (e.g., CH_4 and N_2O), or unexpected changes in total solar irradiance. By 2050, the magnitude of the projected climate change is significantly affected by the overall emissions path along which the world is tracking. It should be noted that, according to the IPCC, only emissions projections following the lowest concentration pathway (RCP2.6) result in an estimated mean increase in global average temperatures below 2°C. Equally important, IPCC scientists project that warming will continue beyond 2100 under all RCP scenarios except for RCP2.6.

The projected increase of global mean surface temperature by the end of the 21st century (2081–2100) relative to 1986–2005 is likely to be 0.3°C to 1.7°C under RCP2.6, 1.1°C to 2.6°C under RCP4.5, 1.4°C to 3.1°C under RCP6.0 and 2.6°C to 4.8°C under RCP8.5. It is virtually certain that there will be more frequent hot and fewer cold temperature extremes over most land areas on daily and seasonal timescales as global mean surface temperature increases. It is also very likely that heat waves will occur with a higher frequency and longer duration. Occasional cold winter extremes will continue to occur due to the inherent variability within the climate system. Changes in precipitation patterns will not be uniform, but in general, scientists expect arid regions to become dryer while wetter areas can expect more frequent exceptional precipitation events. Oceans will continue to warm, with the greatest impacts occurring at the surfaces of tropical and northern hemisphere subtropical regions. Models also predict that ocean acidification will increase for all RCP scenarios, where surface pH can be expected to decrease by 0.06 to 0.07 (15 to 17%) for RCP2.6 and 0.14 to 0.15 (38 to 41%) for RCP4.5. Year-round reductions in Arctic sea ice are projected for all RCP scenarios, and it is virtually certain that near-surface (upper 3.5 m) permafrost extent at high northern latitudes will be reduced (37% - RCP2.6 to 81% - RCP8.5) as global mean surface temperature increases. Global mean sea level rise will very likely continue at a faster rate than observed from 1971 to 2010. For the period 2081–2100 relative to 1986–2005, the rise will likely be in the ranges of 0.26 to 0.55 m for RCP2.6 and of 0.45 to 0.82 m for RCP8.5. It is very likely that the sea level will rise in more than about 95% of the ocean area, where about 70% of coastlines worldwide would experience a sea level change within ±20% of the global mean.

All climate model projections indicate future warming in Colorado. Statewide average annual temperatures are projected to warm by +2.5°F to +5°F by 2050 relative to a 1971–2000 baseline under RCP4.5. Under the high emissions scenario (RCP8.5), the projected warming is +3.5°F to +6.5°F and would occur later in the century as the two referenced scenarios diverge. Summer temperatures are projected to warm slightly more than winter temperatures, where the maximums would be similar to the hottest summers that have occurred in past 100 years. Precipitation projections are less clear, with individual models showing a range of changes by 2050 of -5% to +6% for RCP 4.5%, and -3% to +8% under RCP8.5. Nearly all of the models predict an increase in winter precipitation by 2050, although most projections of snowpack (April 1 snow-water equivalent) show declines by mid-century due to the projected warming. Late-summer flows are projected to decrease as the peak shifts earlier in the season, although the changes in the timing of runoff are more certain than changes in the amount of runoff. In general, the majority of published research indicates a tendency towards future decreases in annual streamflow for all of Colorado's river basins. Increased warming, drought, and insect outbreaks, all caused by or linked to climate change, will continue to increase wildfire risks and impacts to people and ecosystems.

In 2018, the IPCC released a special report on the impacts of global warming of 1.5°C above pre-industrial levels and summarizes their conclusions from a number of key findings, several of which are excerpted here (IPCC 2018):

- Human activities are estimated to have caused approximately 1.0°C of global warming above pre-industrial levels, with a likely range of 0.8°C to 1.2°C, and warming is likely to reach 1.5°C between 2030 and 2052 if it continues to increase at the current rate.
- Warming from anthropogenic emissions from the pre-industrial period to the present will persist for centuries to millennia and will continue to cause further long-term changes in the climate system, but these emissions alone are unlikely to cause global warming of 1.5°C (medium confidence).
- Climate models project robust differences in regional climate characteristics between present-day and global warming of 1.5°C, and between 1.5°C and 2°C. These differences include increases in mean temperature in most land and ocean regions (high confidence), hot extremes in most inhabited regions (high confidence), heavy precipitation in several regions (medium confidence), and the probability of drought and precipitation deficits in some regions (medium confidence).
- By 2100, global mean sea level rise is projected to be around 0.1 m lower with global warming of 1.5°C compared to 2°C (medium confidence). Sea level will continue to rise well beyond 2100 (high confidence), and the magnitude and rate of this rise depend on future emission pathways. A slower rate of sea level rise enables greater opportunities for adaptation in the human and ecological systems of small islands, low-lying coastal areas, and deltas (medium confidence).
- Limiting global warming to 1.5°C compared to 2°C is projected to reduce increases in ocean temperature as well as associated increases in ocean acidity and decreases in ocean oxygen levels (high confidence), all of which will reduce risks to marine biodiversity, fisheries, and ecosystems, and their functions and services to humans.

The following summary text provides an overview of the fourth iteration of the U.S. National Climate Assessment (NCA) report (NCA 2017). The NCA provides region-specific impact assessments for climate change parameters that are anticipated to occur throughout this century. The global climate continues to change rapidly compared to the pace of the natural variations in climate that have occurred throughout Earth's history. Trends in globally averaged temperature, sea level rise, upper-ocean heat content, land-based ice melt, Arctic sea ice, depth of seasonal permafrost thaw, and other climate variables provide consistent evidence of a warming planet. These observed trends are robust and have been confirmed by multiple independent research groups around the world (very high confidence). Many lines of evidence demonstrate that it is extremely likely that human influence has been the dominant cause of the observed warming since the mid-20th century. Formal detection and attribution studies for the period 1951 to 2010 find that the observed global mean surface temperature warming lies in the middle of the range of likely human contributions to warming over that same period. Natural variability, including El Niño events and other recurring patterns of ocean–atmosphere interactions, impact temperature and precipitation, especially regionally, over months to years. The global influence of natural variability, however, is limited to a small fraction of observed climate trends over decades (very high confidence). Studies found no convincing evidence that natural variability can account for the amount of global warming observed over the industrial era. For the period extending over the last century, there are no convincing alternative explanations supported by the extent of the observational evidence. Solar output changes and internal variability can only contribute marginally to the observed changes in climate over the last century, but no convincing evidence for natural cycles in the observational record can explain the observed changes in climate (very high confidence).

The frequency and intensity of extreme heat and heavy precipitation events are increasing in most continental regions of the world, and these trends are consistent with expected physical responses to a warming climate. Climate model studies are also consistent with these trends, although models tend to underestimate the observed trends, especially for the increase in extreme precipitation events (very high confidence for temperature, high confidence for extreme precipitation). The frequency and intensity of extreme high temperature events are virtually certain to increase in the future as global temperature increases (high confidence). Extreme precipitation events will very likely continue to increase in frequency and intensity throughout most of the world (high confidence). Observed and projected trends for some other types of extreme events, such as floods, droughts, and severe storms, have more variable regional characteristics.

Temperatures have increased across almost all of the Southwest region from 1901 to 2016, with the greatest increases in southern California and western Colorado. The integrity of Southwest forests and other ecosystems and their ability to provide natural habitat, clean water, and economic livelihoods have declined as a result of recent droughts and wildfire due in part to human-caused climate change. The cumulative forest area burned by wildfires has greatly increased between 1984 and 2015, with analyses estimating that the area burned by wildfire across the western United States over that period was twice what would have burned had climate change not occurred. Water for people and nature in the Southwest has declined during droughts, which are increasing, along with heat waves, and the reduction of winter chill hours, which can harm crops and livestock; exacerbate competition for water among agriculture, energy generation, and municipal uses; and increase future food insecurity. The ability of hydropower and fossil fuel electricity generation to meet growing energy use in the Southwest is decreasing as a result of drought and rising temperatures. Intensifying droughts and occasional large floods, combined with critical water demands from a growing population, deteriorating infrastructure, and groundwater depletion, suggest the need for flexible water management techniques that address changing risks over time to balance declining supplies with greater demands. Many renewable energy sources offer increased electricity reliability, lower water intensity of energy generation, reduced GHG emissions, and new economic opportunities. Implementing GHG emissions reductions, adaptive fire management, and other resource actions can help reduce future vulnerabilities of ecosystems and human well-being. Heat-associated deaths and illnesses, vulnerabilities to chronic disease, and other health risks to people in the Southwest result from increases in extreme heat, poor air quality, and conditions that foster pathogen growth and spread. Improving public health systems, community infrastructure, and personal health can reduce serious health risks under future climate change.

1.4.2 Effects on Public Health & Safety

The following data have been summarized from the Centers for Disease Control and Prevention's Climate Effects on Health assessment (CDC 2019). Climate change and other natural and human-made health stressors influence human health and disease in numerous ways. Some existing health threats will intensify, and new health threats will emerge as a result of climate change. Key weather and climate drivers of health impacts include increasingly frequent, intense, and longer-lasting extreme heat, which worsen drought, wildfire, and air pollution risks; increasingly frequent extreme precipitation, intense storms, and changes in precipitation patterns that lead to drought and ecosystem changes; and rising sea levels that intensify coastal flooding and storm surges. Key drivers of vulnerability include the attributes of certain groups (age, socioeconomic status, race, and current level of health) and of place (floodplains, coastal zones, and urban areas), as well as the resilience of critical public health infrastructure. Health effects of these disruptions include increased respiratory and cardiovascular disease, injuries, and premature deaths related to extreme weather events; changes in the prevalence and geographical distribution of foodborne and waterborne illnesses and other infectious diseases; and threats to mental health.

Climate change is projected to harm human health by increasing ground-level O_3 and/or PM air pollution in some locations. Ground-level O_3 (a key component of smog) is associated with many health problems, such as diminished lung function, increased hospital admissions and emergency room visits for asthma, and increases in premature deaths. Factors that affect O_3 formation include heat, concentrations of precursor chemicals, and CH_4 emissions, whereas PM concentrations are affected by wildfire emissions and air stagnation episodes, among other factors.

Climate change is currently increasing the vulnerability of many forests to wildfire. Climate change is projected to increase the frequency of wildfires in certain regions of the United States. Long periods of record high temperatures are associated with droughts that contribute to dry conditions and drive wildfires in some areas. Wildfire smoke contains PM, CO_2, NOx, and various VOCs (which are O_3 precursors) and can significantly reduce air quality, both locally and in areas downwind of fires. Smoke exposure increases respiratory and cardiovascular hospitalizations; emergency department visits; medication dispensations for asthma, bronchitis, chest pain, chronic obstructive pulmonary disease (COPD), and respiratory infections; and medical visits for lung illnesses.

Drought conditions may increase environmental exposure to dust storms, extreme heat events, flash flooding, degraded water quality, and reduced water quantity. Dust storms associated with drought conditions contribute to degraded air quality. Extreme heat events have long threatened public health in the United States. Heat waves are also associated with increased hospital admissions for cardiovascular, kidney, and respiratory disorders. Extreme summer heat is increasing in the United States, and climate projections indicate that extreme heat events will be more frequent and intense in coming decades.

Milder winters resulting from a warming climate can reduce illness, injuries, and deaths associated with cold and snow. Vulnerability to winter weather depends on many non-climate factors, including housing, age, and baseline health. Although deaths and injuries related to extreme cold events are projected to decline due to climate change, these reductions are not expected to compensate for the increase in heat-related deaths.

The frequency of heavy precipitation events has already increased for the nation as a whole and is projected to increase in all U.S. regions. Increases in both extreme precipitation and total precipitation have contributed to increases in severe flooding events in certain regions. In addition to the immediate health hazards associated with extreme precipitation events when flooding occurs, other hazards can often appear once a storm event has passed. Elevated waterborne disease outbreaks have been reported in the weeks following heavy rainfall, although other variables may also affect these associations. Water intrusion into buildings can result in mold contamination that manifests later, leading to indoor air quality problems. Buildings damaged during hurricanes are especially susceptible to water intrusion. Populations living in damp indoor environments experience increased prevalence of asthma and other upper respiratory tract symptoms, such as coughing and wheezing, as well as lower respiratory tract infections such as pneumonia, Respiratory Syncytial Virus (RSV), and RSV pneumonia.

Climate is one of the factors that influence the distribution of diseases borne by vectors such as fleas, ticks, and mosquitoes, which spread pathogens that cause illness. The geographic and seasonal distribution of vector populations, and the diseases they can carry, depend not only on climate but also on land use, socioeconomic and cultural factors, pest control, access to health care, and human responses to disease risk, among other factors. Daily, seasonal, or year-to-year climate variability can sometimes result in vector/pathogen adaptation and shifts or expansions in their geographic ranges. North Americans are currently at risk from numerous vector-borne diseases, including Lyme, dengue fever, West Nile virus, Rocky Mountain spotted fever, plague, and tularemia. Vector-borne pathogens not currently found in the United States, such as chikungunya, Chagas disease, and Rift Valley fever viruses, are also potential threats.

Mental illness is one of the major causes of suffering in the United States, and extreme weather events can affect mental health in several ways. For example, research demonstrated high levels of anxiety and post-traumatic stress disorder among people affected by Hurricane Katrina, and similar observations have followed floods and heat waves. Some evidence suggests that wildfires have similar effects. All of these events are increasingly fueled by climate change. Additional potential mental health impacts, less well understood, include the possible distress associated with environmental degradation and displacement, and the anxiety and despair that knowledge of climate change might elicit in some people.

1.4.3 Social Cost of Carbon

A protocol to estimate what is referenced as the “social cost of carbon” (SCC) associated with GHG emissions was developed by a federal Interagency Working Group (IWG) to assist agencies in addressing Executive Order (EO) 12866 (EO 12866), which requires federal agencies to assess the cost and the benefits of proposed regulations as part of their regulatory impact analyses. The SCC is an estimate of the economic damages associated with an increase in CO_2 emissions and is intended to be used as part of a cost-benefit analysis for proposed rules. As explained in the Executive Summary of the 2010 SCC Technical Support Document, “the purpose of the [SCC] estimates… is to allow agencies to incorporate the social benefits of reducing CO_2 emissions into cost-benefit analyses of regulatory actions that have small, or ‘marginal,’ impacts on cumulative global emissions” (Interagency Working Group on Social Cost of Carbon [IWGSCC] 2010). While the SCC protocol was created to meet the requirements for regulatory impact analyses during rulemakings, there have been requests by public commenters or project applicants to expand the use of SCC estimates in NEPA analyses. However, EO 13783, entitled “Promoting Energy Independence and Economic Growth”, issued March 28, 2017, directed that the IWG on the Social Cost of GHGs be disbanded and that technical documents issued by the IWG be withdrawn as no longer representative of governmental policy (Section 5 of the EO) (EO 13783).

BLM is not using the SCC protocol for NEPA analysis and decision for a number of reasons. Most notably, NEPA compliance is not a rulemaking, for which the SCC protocol was originally developed. Second, on March 28, 2017, the President issued Executive Order 13783 which, among other actions, withdrew the Technical Support Documents upon which the protocol was based and disbanded the earlier IWG on Social Cost of Greenhouse Gases. The Order further directed agencies to ensure that estimates of the social cost of GHGs used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in Office of Management and Budget (OMB) Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (EO 13783, Section 5(c)). In compliance with OMB Circular A-4, interim protocols have been developed for use in the rulemaking context. However, the Circular does not apply to NEPA; consequently, there is no Executive Order requirement to apply the SCC protocol to NEPA decisions.

Furthermore, typically, BLM provides for an economic impact analysis within NEPA but not a cost-benefit analysis. Terms such as "benefits" and "costs" can have different and very specific definitions within a discipline, such as economics, which can differ from what the terms may mean in what a person may consider in an "ordinary language sense." While NEPA may use terms such as "benefits," the economic analyses actually conducted are regional economic impact analyses that are the essential effects associated with production or any other forms of economic activities (often expressed in terms of employment, income, and output) and must not be conflated with economic benefits. Net economic benefits are obtained in financial or economic efficiency analyses, not economic impact analyses. The distinction is anything but semantics because principles of cost-benefit analysis prohibits mixing economic impacts into the net benefit calculation.

Whereas an economic impact analysis evaluates changes in economic activity, a cost-benefit analysis is an approach used to determine economic efficiency by focusing on changes in social welfare by comparing whether the monetary benefits gained by people from an action/policy are sufficient to compensate those made worse off by the project and still achieve net benefits (Watson et al. 2007, Kotchen 2011). To summarize, cost-benefit analyses and regional economic impact analyses are very different methods that are focused on quantifying/monetizing different measures (social welfare and economic activity respectively), are based on differing assumptions and terminology, and are not interchangeable. Based on their views and values, people may perceive this increased economic activity as a "positive" impact that they desire; however, that is very distinct from being an "economic benefit" as defined in economic theory and methodology (Watson et al. 2007, Kotchen 2011). Additionally, another person may perceive increased economic activity as a "negative" impact due to potential in-migration of new people, competition for jobs, and concerns that newcomers will change the sense of community and community qualities that are important to herself/himself. Therefore, it is critical to distinguish that how people may perceive an economic impact is not the same as, nor should be interpreted as, a cost or a benefit as defined in a cost-benefit analysis.

The SCC protocol estimates economic damages associated with an increase in CO_2 emissions - typically expressed as a 1 metric ton increase in a single year - and includes, but is not limited to, potential changes in net agricultural productivity, human health, and property damages from increased flood risk over hundreds of years. The estimate is developed by aggregating results "across models, over time, across regions and impact categories, and across 150,000 scenarios" (Rose et al. 2014). The dollar cost figure developed, based on the SCC calculation, represents the value of damages avoided if, ultimately, there is no increase in carbon emissions. But the dollar cost figure is generated in a range and provides little benefit in assisting the authorized officer's decision. The uncertainty of monetizing the costs - and benefits - of potential future NEPA proposed action production makes quantification of the SCC impractical (especially for an oil and gas leasing decision). Moreover, there are no current criteria or thresholds that determine a level of significance to any monetary value calculated by the SCC protocol.

To summarize, BLM does not undertake an analysis of SCC for NEPA because:

1. It is not engaged in a rulemaking for which the protocol was originally developed.
2. The IWG technical supporting documents and associated guidance have been withdrawn.
3. NEPA does not require cost-benefit analysis.
4. The full social benefits of most NEPA actions are not monetized, and quantifying only the costs of GHG emissions but not the benefits would yield information that is both inaccurate and not useful for the decision-maker, especially given that there are no current criteria or thresholds that determine a level of significance for SCC monetary values.

1.4.4 Mitigation

The Proposed Action is unlikely to contribute significantly to air quality degradation in the analysis region. The area is currently in compliance with the NAAQS, and the facility will be required to update or amend existing CDPHE permits to accommodate the additional coal throughput NECC is likely to seek as it resumes operations. The analysis shows the project design features (including Air Pollution Control District [APCD] permit-required controls) are adequate to maintain compliance with the NAAQS. Likewise, the cumulative analysis of the region indicates that restarting the New Elk Mine does not contribute significantly to air quality concerns. Therefore, no additional mitigation is required for the project.

The GHG and climate projections outlined above are based on the best available data and are reasonable given present regulations and public policy. The current and projected pace of global energy demand, and the mix of supply resources that are estimated to meet that demand under a variety of scenarios, make it likely that the entirety of the carbon budget will be consumed at some point in the future. Recall that the area under the curve (integral of emissions) is more important than the timing of emissions, and that at present global emissions rates, the budget will be exhausted in less than 14 years. Anticipated growth in domestic energy demand is likely to contribute to budget pressure even as growth in the renewable energy sector is forecast to continue at the fastest rate on a percentage basis (3.1%). It is unclear how or if public policy advancements, technological advancements, free energy market shifts, governmental energy investments and tax strategies (credits), and global collaboration on these issues will take shape to provide for the changes necessary to transform the make-up of our modern infrastructure to one with a lower carbon state. The tight timeline of the carbon budget makes interim overshoot likely, as well as the need to deploy CDR measures at scale in the future to correct for any overshoot if the global consensus still centers on maintaining warming to 1.5°C. Implementing these types of measures and policy changes are beyond BLM's decision authority.

There are currently no established significance thresholds for GHG emissions to reference in NEPA analyses; however, the BLM acknowledges that all GHGs contribute incrementally to the climate change phenomenon. When determining NEPA significance for an action, BLM Colorado is constrained to the extent that cumulative effects (such as climate change) are only considered in the determination of significance when such effects can be prevented or modified by decision-making (see BLM NEPA

Handbook, pg.72). While individual decision scope emissions of GHGs can certainly be modified or potentially prevented by analyzing and selecting reasonable alternatives that appropriately respond to the action’s purpose and need, BLM Colorado has limited decision authority to provide for meaningful or measurable affects to prevent the cumulative climate change impacts that would result from the global scope emissions. This assertion is supported by the data presented above showing how BLM Colorado's potential projections could contribute to the global emissions context relative to the latest iteration of the carbon budget. In addition, no tools exist to predict the residual impacts of any mitigation that could be reasonably prescribed (up to and including denying the Project), such that the resulting analysis would not be deemed to be arbitrary and capricious upon inspection.

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Arcadis U.S., Inc.

11001 West 120th Avenue

Suite 200

Broomfield, Colorado 80021

Tel 303 544 0043

Fax 720 887 6051

www.arcadis.com