GCCE King II Mine
Dunn Ranch Area LBA and Mining Plan Modification Project

Technical Resources Report

Office of Surface Mining Reclamation and Enforcement

Western Region

1999 Broadway, Suite 3320

Denver, CO 80202

Bureau of Land Management

Tres Rios Field Office

291211 Highway 184

Dolores, CO 81323

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1.0 INTRODUCTION

This Technical Resources Report (TRR) describes the affected environment and environmental effects of the Proposed Action related to the GCC Energy, LLC (GCCE) King II Mine Dunn Ranch Area Lease by Application (LBA) and Mining Plan Modification on air, climate, water, and cultural resources (**Figure 1.1-1**). This TRR was compiled in support of the GCCE King II Dunn Ranch Area LBA and Mining Plan Modification Environmental Assessment (EA) being prepared by the Office of Surface Mining Reclamation and Enforcement (OSMRE) and Bureau of Land Management (BLM).

Please see the EA developed for this Project for a detailed description of the Proposed Action and alternatives. Proposed design Features associated with this Project are located in Appendix B of the EA.

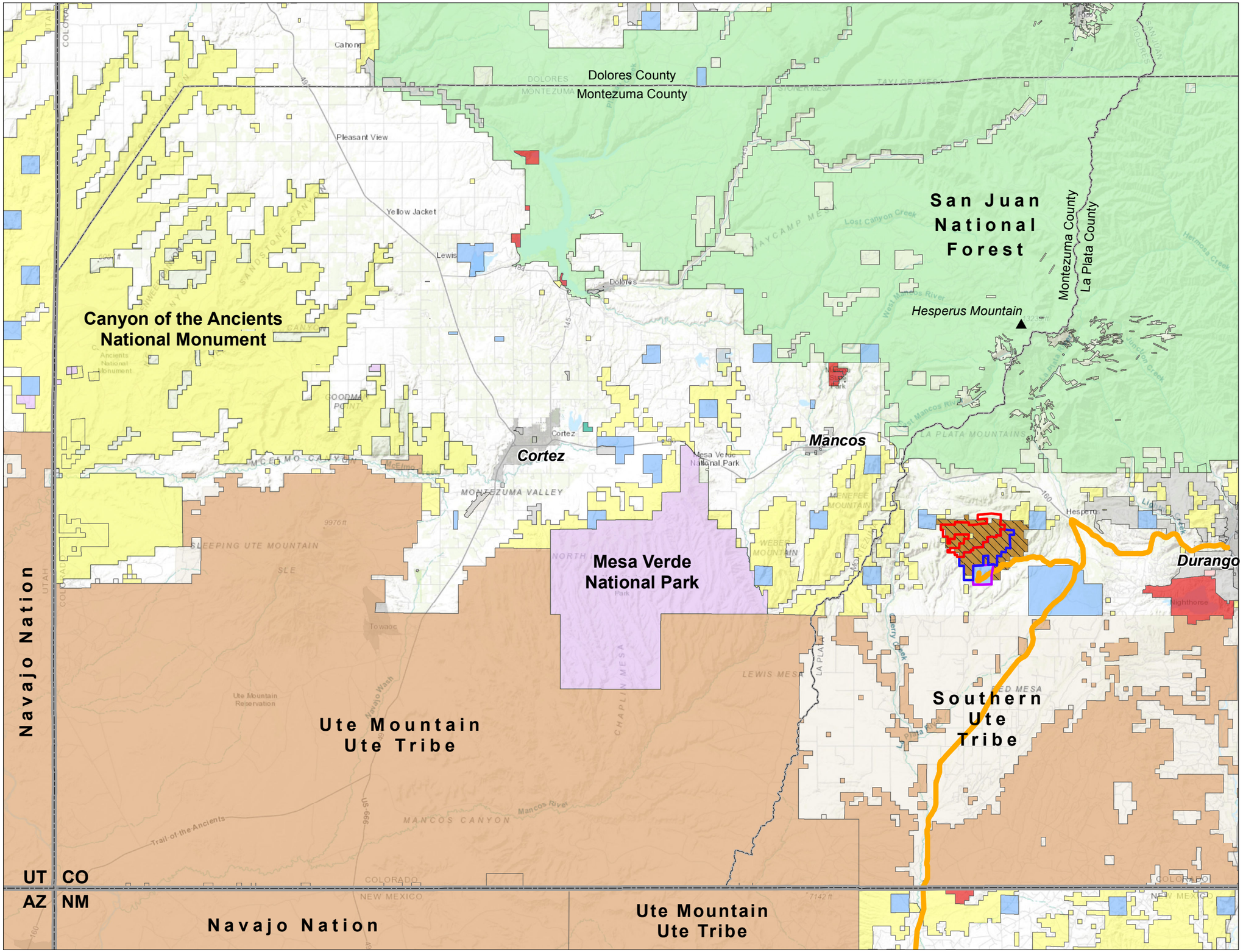


Figure 1.1-1

Title

Regional Location Map

Client/Project

GCCE King II Mine Dunn Ranch Area
Lease By Application Project

Project Location:
La Plata County, CO.

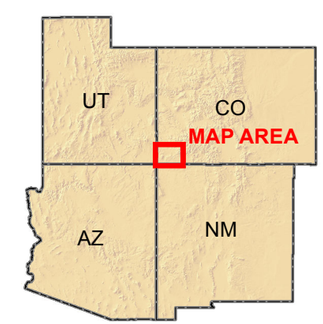
Prepared by:	JSB	2018-01-05
Technical Review by:	NL	2018-01-05
Independent Review by:	DK	2018-01-05

Last Modified: November 07, 2018

- Dunn Ranch Area Lease By Application
- GCC King II Mine Federal Permit CO-0106C
- GCC King II Mine CDRMS Permit Area
- Coal Haul Route

Land Ownership

- Bureau of Land Management
- U.S. Forest Service
- National Park Service
- Indian Reservation
- Ute Mountain Ute Fee Restricted
- Bureau of Reclamation
- State
- Local
- Private



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2.0 AFFECTED ENVIRONMENT AND ENVIRONMENTAL EFFECTS

2.1 Introduction

This section presents the affected existing environment (i.e., the physical, biological, social, and economic values and resources) of the affected area for specific resources. This section also analyzes the potential environmental impacts of the Proposed Action. Within this section, the terms effects and impacts are used interchangeably. The potential impact of the Proposed Action is evaluated for the affected area for each resource in terms of direct, indirect, and cumulative effects.

- Direct effects are those that are caused by an action in the alternative and occur at the same time and place as the action.

- Indirect effects are those that are caused by the action and are later in time or farther removed in distance but are still reasonably foreseeable. Indirect effects may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems.

The duration of impacts is generally in terms of “short term” which is less than 5 years (yr), or “long term” lasting beyond 5 years.

Cumulative effects are defined as "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes other such actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." (40 CFR 1508.7)

For cumulative effects, baseline conditions include past, present, and reasonably foreseeable future conditions in the affected area. The past and present uses of the Dunn Ranch LBA include coal mining, historic oil and gas exploration and limited development, livestock grazing, and wildlife habitat. Reasonably foreseeable future activities include continued underground coal mining and exploration, continued area coal leasing, continued surface coal mine reclamation, continued oil and gas operations and potential development, agriculture and livestock grazing, dispersed residential development, recreation, and wildlife habitat. The past and present actions are provided in greater detail in the 2017 EA (BLM and OSMRE 2017). These various activities are consistent with reasonably foreseeable future activities described in the Tres Rios Field Office (TRFO) Resource Management Plan (RMP; BLM 2015). The affected area for cumulative effects varies by resource and is specified with the effects.

2.2 Air and Climate Resources

2.2.1 Affected Environment

2.2.1.1 Airshed for Analysis

The affected environment for the air quality analysis includes La Plata and Montezuma counties, although most direct air quality impacts would be limited to the vicinity of the mine itself (BLM and OSMRE 2017, Map A-5). Indirect effects associated with coal transport and combustion occur at numerous locations. Most of the coal produced (approximately 83 percent) is transported by truck to a rail terminal in Gallup, New Mexico. Approximately 1,067,040 tons per year (tpy) can be delivered to markets in the southwestern U.S. via the Gallup rail hub. Of the total, approximately 181,000 tpy are delivered by truck to two GCC-owned and operated cement plants in Pueblo, Colorado (105,000 tpy) and in Tijeras, New Mexico (76,000 tpy) where the coal is used as a fuel source in the cement manufacturing process. Small coal volumes are also sold and delivered by truck to the Durango & Silverton Narrow Gauge Railroad (3,600 tpy), the Cumbres and Toltec Scenic Railroad in Chama, New Mexico (1,500 tpy), and locally (7,000 tpy) for home heating. The remaining approximately 880,940 tons would be delivered by rail from the rail terminal in Gallup, New Mexico to GCC-owned cement plants in northern Mexico (240,000 tpy) and to variable cement facilities in Arizona and Texas. It is unknown as to which cement plant(s) King II coal may potentially be sent within Arizona and Texas, or even to which more general geographic areas within those states. This is because of two reasons: 1.) the facilities in those states that are potential purchasers of King II coal are not necessarily owned by GCC; and, 2.) most importantly, no further information is available about future potential sales in these areas as the markets are highly variable and speculative from year to year. Although the Northern Mexico facilities are GCC-owned, Mexico is a different air quality regulatory jurisdiction than the U.S where U.S. standards and regulations do not apply.

2.2.1.2 Regulatory Requirements

The regulatory framework for air quality includes both federal and state rules, regulations, and standards promulgated by the Environmental Protection Agency (EPA) and implemented by the Colorado Department of Public Health and Environment (CDPHE). The Clean Air Act (CAA) established the National Ambient Air Quality Standards (NAAQS) for seven criteria pollutants. The criteria pollutants include carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone (O_3), particulate matter 10 microns (PM_{10}) or less in diameter, particulate matter 2.5 microns ($PM_{2.5}$) or less in diameter, and sulfur dioxide (SO_2) (**Table 2.2-1**).

Pursuant to the CAA, the EPA has developed classifications for distinct geographical regions known as Air Quality Control Regions. In Colorado, the state has been divided into eight multi-county areas that are generally based on topography and have similar airshed characteristics. The Project Area airshed analysis area (**Section 2.2.1**) lies in the Southwestern Air Pollution Control Region as designated by the State of Colorado. The EPA designates whole or partial counties as Attainment, Non-Attainment, or Maintenance for each criteria air pollutant. Regions classified as in Attainment are areas in which the pollutant has not exceeded the NAAQS. A Non-Attainment classification represents an area in which the pollutant has exceeded the NAAQS. The Maintenance designation is used when monitored pollutants have been reduced from the Non-Attainment to the Attainment levels. La Plata and Montezuma counties have been

designated as Attainment for all criteria pollutants based on monitoring results that were below the applicable NAAQS (all Colorado communities are currently in attainment of all NAAQs except the Front Range O_3 control area, which is in nonattainment [moderate] for the eight-hour O_3 standard).

Table 2.2-1 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
Ozone (O_3)		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 µg/m^3	Annual mean, averaged over 3 years
		Secondary	Annual	15 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

Source: http://www.epa.gov/air/criteria.html as of October 2015
µg/m3 = micrograms per cubic meter of air
ppm = parts per million, ppb = parts per billion
*State standard established by the Colorado Air Quality Control Commission

The CAA also divides areas where air quality is already cleaner than required by federal standards into three classes, and specifies the increments of SO_2, NO_2 and particulate pollution allowed in each class as regulated by the Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21). Class I areas include international and national parks, wilderness, and other pristine areas; allowable increments of new pollution in these areas are very small. Class II areas include all attainment and not classifiable areas, which are not designated as Class I; allowable increments of new pollution in these areas are modest.

Class III represents selected areas that states may designate for development; allowable increments of new pollution are large (but not exceeding NAAQS). No Class III areas are designated in Colorado. All areas not designated as Class I are initially designated as Class II areas. The Project Area is located in a Class II area as codified in the Colorado State PSD permitting rules[1].

The PSD regulations are applicable to a source pollutant if the source has the potential to exceed the major source thresholds, of either 100 or 250 tpy of a regulated New Source Review pollutant, depending on the type of source pollutant that it is. For stationary source categories listed in the regulation, the threshold is 100 tpy. For source categories that are not listed, such as surface mining operations, the threshold is 250 tpy. The potential to emit calculation does not include fugitive emissions for the purpose of determining if the facility exceeds the 250 tpy threshold. Fugitive emissions are defined by EPA as "those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening." The Project is classified under the CAA as a PSD minor source of air quality emissions and would not exceed these thresholds under the PSD regulations because the majority of the Project emissions sources are fugitive in nature and as such are not included in the determination of PSD applicability for a non-listed source category such as coal mining. Project emissions estimates are included in **Section 2.2.2.1**. Therefore, PSD regulations and preconstruction monitoring would not be applicable to the mine. It should be noted that minor sources while not subject to PSD regulations can affect increments, but emissions remain below increment thresholds. For further detail please refer to reference, Environ 2017, specifically the tables in Section 5.1.1. Of the scenarios appropriate for this analysis (see **Section 2.2.6.1** below), R, H and A2, there were no Class I or Class II PSD increments exceeded.

Stationary sources that combust coal from the King II Mine that are regulated under PSD include the Pueblo and the Tijeras cement facilities located near Pueblo, Colorado and Albuquerque, New Mexico, respectively.

Federal PSD regulations limit the maximum allowable increase in ambient pollutant concentration in Class I, Class II, and Class III areas (**Table 2.2-2**). The closest Class I areas to the Project Area (BLM and OSMRE 2017; Map A-5) include Mesa Verde National Park, about 14 miles (22.5 kilometers [km]) to the west, and the Weminuche Wilderness Area located 25 miles (40.2 km) to the northwest. For the known indirect sources of substantial emissions within the USA (the Pueblo and Tijeras cement facilities), the closest Class I areas are the Great Sand Dunes National Park and Preserve in Colorado (approximately 50 miles [80 km] to the west southwest), and the Bandalier National Monument and Pecos Wilderness Area in New Mexico (approximately 44 miles [70 km] north of the facility) (BLM and OSMRE 2017, Map A-5).

[1] 5 CCR 1001-05, Regulation Number 3, Part D, Concerning Major Stationary Source New Source Review and Prevention of Significant Deterioration

Table 2.2-2 Federal Prevention of Significant Deterioration Limits

Pollutant	Averaging Time	Maximum Allowable Increase (µg/m³)		
		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

µg/m³ = micrograms per cubic meter of air

The CAA also enacted the New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for specific types of equipment located at new or modified stationary pollutant sources. NSPS regulations limit emissions from source categories to minimize the deterioration of air quality. Stationary sources are required to meet these limits by installing newer equipment or adding pollution controls to older equipment that reduce emissions below the specified limit. The Project Area would include equipment that is subject to various NSPS in 40 CFR Part 60, Subpart Y. NSPS and NESHAP standards also apply to the locations of final coal combustion.

The CAA Amendments of 1990 introduced a new facility-wide Federal Operating Permit program. Federal Operating Permits, also known as Title V permits, are required for facilities with the potential to emit more than 100 tpy of a regulated pollutant, 10 tpy of any single hazardous air pollutant (HAP), or 25 tpy of any combination of HAPs and considered to be major sources of air quality emissions. No NAAQS exist for HAPs; instead emissions of these pollutants are regulated by a variety of laws (e.g., NESHAPs) that target the specific source class and industrial sectors for stationary, mobile, and product use/formulations. However, Title V permitting is still required if HAP emissions rise above the defined thresholds.

The mine's potential to emit is below the requirements to obtain a Federal Operating Permit and, therefore, it would not be subject to Title V permitting. Title V operating permit requirements are typically applicable for the locations of final coal combustion. Both the Pueblo and Tijeras cement facilities have Title V permit applicability.

The PSD regulations described previously also regulate the degradation of Air Quality Related Values (AQRV) in Class I areas. The authority to protect AQRVs in federally mandated Class I areas is to be done as part of the pre-construction permitting process of major sources. AQRVs include all resources sensitive to changes in air quality and typically include visibility degradation, pollutant deposition on vegetation and water bodies, and acidification of sensitive water bodies.

In addition to PSD AQRV analyses, visibility impacts are also included under a State Implementation Plan for the reduction of Regional Haze. This regulation is used to reduce the visibility impacts from existing facilities and introduce additional emissions controls to a standard known as Best Available Retrofit Technology.

Deposition is the process by which pollutants are removed 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.

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. The ability of a pollutant to cause various degrees of visibility impacts is primarily a function of its physical size, and chemical composition and properties. Visibility can be expressed in terms of deciview (dv) or standard visual range (km). A change of one dv is approximately a 10 percent 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.

2.2.1.3 Regional Air Quality

The Project Area and vicinity is currently in Attainment or unclassified for all criteria pollutants. Monitoring of criteria pollutants in the region is located near population centers or areas of specific interest. In the late 1990s, the EPA allowed monitoring to cease where pollutants were less than 60 percent of the NAAQS, and as a result the data collected for this analysis is regionally representative but often monitored at some distance from the Project Area.

Table 2.2-3 shows recent ambient air quality monitor data for potential pollutants of concern from monitors located in or nearby the affected area. The primary pollutant of concern from the Proposed Action is particulate matter (as determined from the emissions inventory presented below). The area monitors also show that O_3 levels are relatively close to the new standard promulgated by EPA in 2015. The O_3 NAAQS is the 4th high averaged over 3 years. There are no 3-year periods that exceed the 70 ppb. A couple of individual years from 2012 to 2017 resulted in a 4th high greater than 70 ppb, but the highest 3-year average is the La Plata site from 2015 to 2017, which is approximately 99.0 percent of the standard. Therefore, the region remains in attainment for O_3. All the monitoring data is from the USEPA's AQS Data Mart (https://www.epa.gov/outdoor-air-quality-data) and excludes exceptional events. The database contains ambient air pollution data collected by USEPA, state, local, and tribal air pollution control agencies, and from various federal land managers from thousands of monitors. Monitoring data is limited, and all pollutants are not monitored at all monitoring locations, and thus data for a pollutant may not be available for all portions of the affected environment. For example, monitoring data for Pueblo County, CO is limited to PM_{10} and $PM_{2.5}$. The location of air quality monitoring stations within the Project analysis

area are depicted in **Figure 2.2-1**. The closest O_3 monitoring is in El Paso County to the north, which is going to be more highly influenced (if not totally) by the Colorado Springs metropolitan area versus Pueblo area emissions sources. Air quality within the Project Area and within the vicinity of the indirect sources is generally considered good, and all identified areas are currently in attainment status for all criteria pollutants.

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 (EPA 2014) presented in **Table 2.2-4** shows the amount of pollutants released within the Project and indirect source areas. Combined with the available monitoring data shown above, readers can get a sense of the localized atmospheric response to the emissions loading occurring near the ambient air quality monitors. The NEI data by default includes all the Project and indirect source emissions (as shown below), as these sources and supporting emissions generating activities have been in existence for several NEI reporting periods (the NEI is produced every 3 years). Despite this fact, the areas remain in attainment for all the NAAQS.

2.2.1.4 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 NESHAP Air Pollutants 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 Project would be the result of vehicle use. The largest components of the HAPs emissions from these sources are typically various benzene compounds and formaldehyde. The major source threshold for HAPs is 10 tpy of any one HAP or 25 tpy of aggregate HAPs. Most of the HAPs emitted from the King II Mine's operations are the result of the on and off-road vehicle use. The largest components of the HAPs emissions from these sources are typically various benzene compounds and formaldehyde.

Figure No.
2.2-1

Title
Regional Air Quality Monitoring

Client/Project
GCCE King II Mine Dunn Ranch Area Lease By Application Project

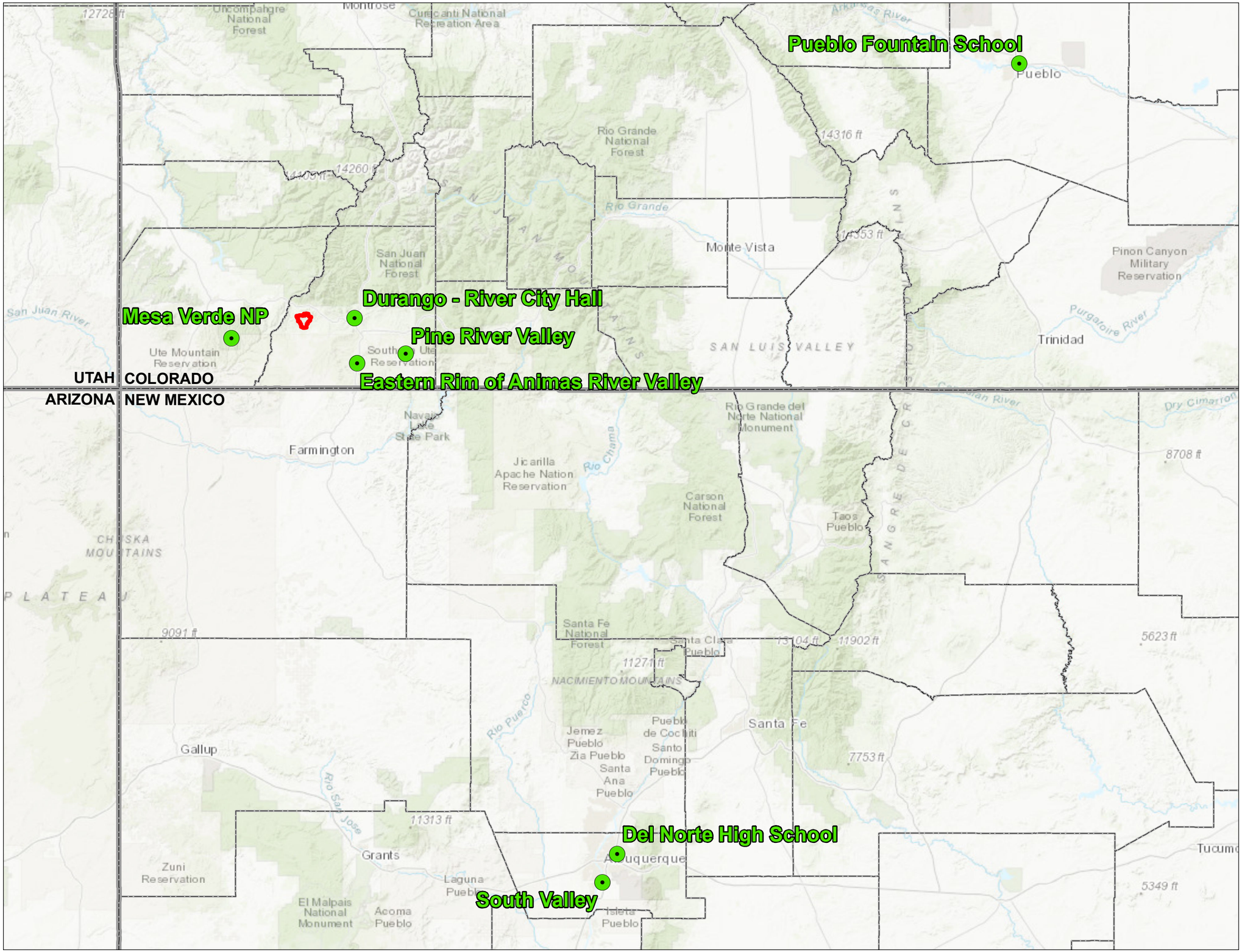
Project Location:
La Plata County, CO.

Prepared by:	JSB	2018-01-05
Technical Review by:	NL	2018-01-05
Independent Review by:	DK	2018-01-05

Last Modified: November 16, 2018

Project Area

Monitoring Station



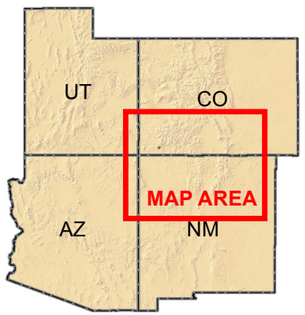


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Table 2.2-3 Regional Ambient Air Quality Monitoring Results

Pollutant	Averaging Time	County	AQS - Site	Agency	2012	2013	2014	2015	2016	2017	Percent of NAAQS
$PM_{2.5}$	Annual (µg/m^3)	La Plata	08-067-7003	South Ute Tribe	3.9	4.0	3.8	3.4	6.0	6.5	38.2%
		Bernalillo	35-001-0023	Albuquerque EHD	11.3	8.7	7.4	6.7	5.4	7.2	64.9%
		Pueblo	08-101-0015	CDPHE	6.6	6.5	5.7	5.3	4.8	4.7	46.6%
	24-hour (µg/m^3)	La Plata	08-067-7003	South Ute Tribe	10	29	10	7.2	10	9.6	25.5%
		Bernalillo	35-001-0023	Albuquerque EHD	25	20	23	21	18	20	56.0%
		Pueblo	08-101-0015	CDPHE	17	17	12	22	10	15	44.8%
PM_{10}	24-hour (µg/m^3)	La Plata	08-067-0004	CDPHE	59	34	34	37	62	36	29.1%
		Bernalillo	35-001-0029	Albuquerque EHD	145	120	143	126	187	84	89.4%
		Pueblo	08-10-0015	CDPHE	50	62	77	46	64	38	37.4%
NO_2	Annual (ppb)	La Plata	08-067-7003	South Ute Tribe	5.5	5.6	4.7	4.5	5.0	5.0	9.5%
		Bernalillo	35-001-0023	Albuquerque EHD	14	12	12	11	10	13	22.8%
	1-hr (ppb)	La Plata	08-067-7003	South Ute Tribe	29	35	24	25	22	21	22.7%
		Bernalillo	35-001-0023	Albuquerque EHD	49	45	42	43	44	45	44.0%
O_3	8-hr (ppm)	La Plata	08-067-7001	South Ute Tribe	0.067	0.069	0.067	0.068	0.071	0.069	99.0%
		Bernalillo	35-001-0029	Albuquerque EHD	0.072	0.067	0.065	0.068	0.063	0.066	93.8%
		Montezuma	08-083-0101	National Park Service	0.069	0.069	0.065	0.066	0.066	0.066	94.3%

Notes: NO_2 = nitrogen dioxide; ppb = parts per billion; O_3 = ozone; ppm = parts per million; µg/m^3 = micrograms per cubic meter, $PM_{2.5}$ = particulate matter emissions that are less than of 2.5 microns in diameter; PM_{10} = particulate matter emissions that are less than 10 microns in diameter.

Where multiple monitors for single pollutant exist within the same county, the monitor with the highest values is presented to the reader for the purposes of this analysis. For each pollutant with a multiyear standard (O_3, NO_2, $PM_{2.5}$), the percent NAAQS is calculated for the most recent three-year averaging period (2015-2017).

Table 2.2-4 2014 NEI Data (tpy)

County	PM_{10}	$PM_{2.5}$	VOC	NO_x	CO	SO_2	CO_2	CH_4	N_2O	HAPs
La Plata	8,538	1,490	29,432	7,756	21,658	111	409,893	148	11	4,154
Montezuma	5,589	931	24,349	1,318	10,175	45	234,355	80	6	4,836
Pueblo	7,474	1,696	18,668	12,015	28,797	3,569	926,481	97	35	4,453
Bernalillo	42,225	6,024	28,719	17,326	73,744	649	3,028,848	315	73	4,948

Notes: NO_x = nitrogen oxides. The 2014 NEI data includes all emissions generating activities (sectors) within a reporting area (county). Sector examples include agriculture, industrial processes, fuel combustion, mobile sources/road dust, waste disposal fires, and other retail operations. Note: The greenhouse gas data (CO_2, CH_4, N_2O) data is limited to mobile sources and fires only.

2.2.1.5 Existing Air Pollutant Emission Sources

There is a total of 141 permitted air quality emission sources that are currently located within 31 miles (50 km) of the Project Area. The region is generally rural, and the emissions sources are dominated by mining, power generation, oil and gas production, and aggregate (sand and gravel) processing (CDPHE 2018). CDPHE (2018) includes in its permits all sources of air quality emissions that are required by law to acquire a state air quality 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 but have the capacity to produce air quality emissions regionally.

Table 2.2-5 illustrates the actual emissions data that have been submitted to CDPHE on an annual basis within 31 miles (50 km) of the mine site.

Table 2.2-5 CDPHE Reported Actual Emissions Summary

Air Pollution Emission Notice Annual Actual Pollutant Emissions (tpy)					
PM_{10}	$PM_{2.5}$	CO	NO_2	SO_2	VOC[1]
130.85	33.51	1,826.76	596.11	5.75	284.6

[1] volatile organic compound

2.2.1.6 Climate Change

The primary natural and synthetic greenhouse gases (GHGs) in the Earth's atmosphere are water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. GHGs allow heat from the sun to pass though the upper atmosphere and warm the earth by blocking some of the heat that is radiated from the earth back into space. As GHG concentrations increase in our atmosphere they impact the global climate by further decreasing the amount of heat that is allowed to escape back into space. Many GHGs are naturally occurring in the environment; however, human activity has contributed to increased concentrations of these gases in the atmosphere. CO_2 is emitted from the combustion of fossil fuels (i.e., oil, natural gas, and coal), solid waste, trees and wood products, and also as a result of other chemical reactions (e.g., manufacture of cement). Methane results from livestock and other agricultural practices and by the decay of organic waste in municipal solid waste landfills. Methane is also emitted during the production and transport of coal, natural gas, and oil. Nitrous oxide is emitted during

agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste. Fluorinated gases, while not abundant in the atmosphere, are powerful GHGs that are emitted from a variety of industrial processes and are often used as substitutes for O_3-depleting substances (e.g., chlorofluorocarbons, hydrochloroflourocarbons, and halons).

All 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 since 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, and so for the purposes of analysis a GHGs GWP is generally standardized to a CO_2 equivalent (CO_2e), or the equivalent amount of CO_2 mass the GHG would represent. Methane has a current GWP estimated to be between 28 (gas alone) and 36 (with climate feedbacks), and N_2O has a GWP of 298.

The EPA tracks GHG emissions in the U.S. by source sector (e.g., industrial, land use, electricity generation, etc.), fuel source (e.g., coal, natural gas, geothermal, petroleum, etc.), and economic sector (e.g., residential, transportation, commercial, agriculture, etc.) (**Table 2.2-6**). With so many GHG emission sources nationally, from cattle to vehicles to electric power generators, no single source is likely to represent a significant percentage of national emissions (**Table 2.2-6**). Nevertheless, GHG emissions for the U.S. are provided here in several ways. **Table 2.2-6** shows GHG emissions CO_2e from fossil fuel combustion by economic sectors for 2005, 2012, and 2016. **Table 2.2-7** shows total U.S. emissions in 2005, 2012, and 2016 by gas and source and by CO_2e; only the largest sources/sinks are shown for each gas. Note that, for CO_2, "Land Use, Land-Use Change, and Forestry" represents a sink rather than a source and is therefore in parentheses.

Table 2.2-6 U.S. Greenhouse Gas Fossil Fuel Combustion Emissions Allocated to Economic Sectors (million metric tons)

Implied Sectors	2005 (MMT CO_2e)	2012 (MMT CO_2e)	2016 (MMT CO_2e)
Electric Power Industry	2,400.9	2,022.2	1,809.3
Transportation	1,855.8	1,661.9	1,782.6
Industry	855.7	812.9	809.1
Commercial	227.0	201.3	231.3
Residential	357.8	282.5	292.5
U.S. Territories	49.7	43.5	41.4
Total Emissions	**5,746.9**	**5,024.4**	**4,966.0**

MMT = million metric tons;
Source: EPA (2018)
equivalentshttps://www.epa.gov/sites/production/files/201801/documents/2018_complete_report.pdf. Table ES-2.

Table 2.2-7 U.S. Greenhouse Gas Emissions and Sinks

Gas/Source	2005 (MMT CO_2e)	2012 (MMT CO_2e)	2016 (MMT CO_2e)
CO_2	**6,132.0**	**5,366.7**	**5,310.9**
Fossil Fuel Combustion	5476.9	5,024.4	4,966.0
Non-Energy Use of Fuels	138.9	108.0	112.2
Iron and Steel Production and Metallurgical Coke Production	68.2	55.6	42.3
Cement Manufacture	46.2	35.3	39.4
Natural Gas Systems	22.5	23.3	25.5
CH_4	**688.6**	**662.5**	**657.4**
Enteric Fermentation	168.9	166.7	170.1
Landfills	132.7	117.0	107.7
Natural Gas Systems	169.1	159.6	163.5
Coal Mining	64.1	66.5	53.8
Manure Management	56.3	65.6	67.7
N_2O	**357.8**	**335.8**	**369.5**
Agricultural Soil Management	253.8	247.9	283.6
Mobile Combustion	38.8	24.3	18.4
Nitric Acid Production	11.3	10.5	10.2
Stationary Combustion	17.5	16.9	18.6
Manure Management	16.5	17.5	18.1
HFCs, PFCs, and SF6	**141.5**	**163.1**	**172.8**
Substitution of O_3-Depleting Substances	102.7	144.8	159.1
HCFC-22 Production	20.0	5.5	2.8
Electrical Transmission and Distribution	8.3	4.7	4.3
Total Emissions	**7,320.3**	**6,528.8**	**6,511.3**
Land Use, Land-Use Change, and Forestry (Sink)	(731.1)	(753.5)	(716.8)
Net Emissions (Sources and Sinks)	**6,589.1**	**5,775.3**	**5,794.5**

Source: EPA (2018) https://www.epa.gov/sites/production/files/2018-01/documents/2018_complete_report.pdf.
The subtotals represent only the highest contributing sources.

Secondary GHGs do not have a direct atmospheric warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric O_3, or in the case of SO_2, the absorptive characteristics of the atmosphere.

Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are GHGs. **Table 2.2-8** provides national emissions of SO_2 for years 2005, 2012, and 2016. Levels of SO_2 emissions have decreased since 2005 due to reductions in electricity generation, but

primarily due to increased consumption of low sulfur coal from surface mines in the western states and the installation of control equipment utilized by generators.

Table 2.2-8 U.S. Sulfur Dioxide (Indirect GHG) Emissions

Gas/Source	GHG 2005 (MMT)	GHG 2012 (MMT)	GHG 2016 (MMT)
Combustion (fossil fuel stationary and mobile, waste)	11.75	5.13	1.92
Industrial Processes	0.83	0.60	0.50
Oil & Gas Activities	0.62	0.14	0.44
Total SO_2 Emissions	**13.20**	**5.88**	**2.46**

NAAQS 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 EPA determined that GHGs are air pollutants subject to regulation under the CAA. GHGs' status as pollutants are due to the added long-term impacts they have on the climate because of their increased concentrations in the earth's atmosphere. Ongoing scientific research has identified that anthropogenic GHG emissions impact the global climate. Industrialization and the burning of fossil fuels have contributed to increased concentrations of GHGs in the atmosphere. GHGs are produced from both the direct process of coal mining as well as from the combustion of the mined coal. The amount of GHG emissions associated with both processes varies greatly based on mining techniques and combustion methodologies used.

The EPA has promulgated rules to regulate GHG emissions and the industries responsible under the Mandatory Reporting Rule (74 FR 56260, 40 CFR 98) and the Tailoring Rule (70 FR 31514, 40 CFR 51, 52, 70, 71). Under the EPA's GHG Mandatory Reporting Rule, coal mines subject to the rule are required to report emissions in accordance with the requirements of Subpart FF. Subpart FF is applicable only to underground coal mines and is not applicable to surface coal mines. Under the provisions of the Tailoring Rule (and a subsequent Supreme Court decision[2]), a facility would be subject to PSD permitting if it has the potential to emit GHGs in excess of 100,000 tpy of CO_2e and the facility exceeded the PSD major source threshold for a criteria pollutant. For existing facilities this review would take place during any subsequent modifications to the facility. Based on emissions estimates for the King II Mine, no GHG reporting or permitting would apply to the facility.

Global warming of approximately 2°C (above the pre-industrial baseline) is very likely to lead to more frequent extreme heat events and daily precipitation extremes over most areas of North America, more frequent low snow years, and shifts towards earlier snowmelt runoff over much of the western U.S. and Canada (IPCC 2013). Together with climate hazards such as higher sea levels and associated storm surges, more intense droughts, and increased precipitation variability, these changes are projected to lead to increased stresses to water, agriculture, economic activities, and urban and rural settlements.

[2] *Utility Air Regulatory Group v. EPA*, U.S., 134 S. Ct. 2427 (June 23, 2014)

GHGs and Coal Mining

CO_2 is the primary GHG emitted through human activities that contributes to climate change (81 percent of total United States GHG emissions in 2016); it is followed by CH_4 (10 percent of total 2016 emissions), N_2O (6 percent of total 2016 emissions), and fluorinated gases (3 percent of total 2016 emissions) (EPA 2017). The main human activity emitting CO_2 is the combustion of fossil fuels (including the combustion of coal) for energy and transportation (EPA 2017). Coal combustion for electric power and industry produces CO_2 emissions in addition to non-GHG pollutants such as SO_2, NO_X, PM, mercury (Hg), and other heavy metals. During underground mining operations, CH_4, is released from ventilation systems and generally has higher CH_4 content of coal than surface mines due to deeper underground coal seams. However, at the King II mine, CH_4 are naturally low because the coal daylights around the outcrop and has already offgassed. In addition, minor amounts of CH_4 are released during coal blasting, extraction, storing, loading, and transport. CH_4 is also released during post-mining operations as the coal is processed, transported, and stored for use. Methane is also emitted from the production and transport of natural gas and oil, as well as from livestock, other agricultural practices, and the decay of organic waste in municipal solid waste landfills (EPA 2017). N_2O is emitted from agricultural and industrial activities, as well as during the combustion of fossil fuels and solid waste. Fluorinated gases, which are synthetic, are emitted from a variety of industrial processes. Total underground mining CH_4 emissions in MMT CO_2e in 2016 was 45.6. 57.1 MMT was liberated, post Mining emissions was 4.8 MMT with 16.3 MMT being recovered and used (EPA 2018).

2.2.1.7 Black Carbon

Black carbon is a by-product of incomplete combustion of fossil fuels, biofuels, and biomass. It can be emitted when coal is burned, as well as through tailpipe emissions from engines that use diesel fuel (such as diesel trucks and locomotives). Black carbon is a likely by-product that is emitted from haul trucks used during coal mining operations. Black carbon is an unregulated pollutant; however, the EPA does regulate diesel fuel quality, such that in recent years diesel fuel quality has been improved.

Black carbon emissions associated with coal combustion occur at the facility where the coal is burned, not where it is being mined. Black carbon is an unregulated pollutant. According to the 2012 Report to Congress on Black Carbon, the bituminous and sub-bituminous coal categories, both of which primarily represent electricity generating units but may also reflect small contributions from commercial and institutional sources, represent relatively small contributions to black carbon emissions in the U.S. (slightly more than 1 percent each)[3]. At the mine, black carbon occurs as a result of the use of diesel vehicles. Black carbon is a component of the anthropogenic climate phenomenon; however, it is very short-lived, staying in the atmosphere only a few days to a few weeks. Although short lived, while in the atmosphere black carbon is the most strongly light-absorbing component of particulate matter[4]. Black carbon can absorb a million times more energy than CO_2. Black carbon is a major component of “soot”, a complex light-absorbing mixture that also contains some organic carbon.

[3] USEPA 2012, Report to Congress on Black Carbon March 2012, Department of the Interior, Environment, and Related Agencies Appropriations Act, 2010. EPA-450/R-12-001

[4] http://www.epa.gov/blackcarbon/basic.html

2.2.2 Environmental Effects

The BLM has developed a statewide Air Resource Protection Protocol, which is a strategy to address air resource concerns consistently across district and field offices (BLM 2013). This protocol is followed in this analysis to evaluate potential impacts to air resources. Under the Proposed Action, the King II Mine would continue to produce and transport coal at levels below the maximum allowable production limit of 1.3 million tpy (limit is per CDPHE Air Quality Permit No. 09LP0202F, Final Approval – Modification 1, Condition No. 2, dated 9/3/2013). Additionally, haul truck traffic is limit to 1.1 million tpy in accordance with road use agreement (Project # 2012-0089) from La Plata County (LPC). It ultimately limits the truck trips to a maximum of 120 per day. A more realistic annual maximum tons are 800,000 burned. This is based on estimated future coal market conditions and expected future coal contracts.

For this air analysis, direct annual emissions calculations are based on each of the three scenarios: producing an estimated 800,000 tons, 1.1 million tons, and 1.3 million tons. However, the total tonnage produced estimated throughout the life of the mine (22 years) is 17 million tons.

2.2.2.1 Direct Emissions

With exception of particulate matter, all the directly emitted criteria pollutants from the King II Mine's operations are from fuel combustion sources, such as mobile mining equipment, haul trucks, and stationary sources such as emergency generators, heaters. Also, coal mine CH_4 (CMM) is 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. Due to the area's naturally low occurrence of gas in the coal formation, overburden, surrounding strata as well as GCCE's room and pillar mining methods, this is the only CH_4 ventilation system required at the King II Mine. The ventilation air CH_4 emissions estimates are based on a single CH_4 concentration measurement (the highest ever recorded by MSHA at the mine was 0.02 percent) and the main vent fan air flow used by CDPHE to estimate vent particulate matter emissions. Stationary sources (including any area and fugitive emissions) at the King II Mine are regulated by CDPHE and are authorized by Air Pollution Control District (APCD) permit number 09LP0202F. **Table 2.2-9** provides permitted emission limits by source ID. Several pieces of stationary equipment at the King II Mine are also covered by NSPS Subpart Y, which specifies emissions standards for coal preparation plants. The APCD permit only covers source of particulate matter. None of the other pollutants emitted by stationary sources are generated in quantities significant enough to warrant permitting.

Table 2.2-9 CDPHE Permit 09LP0202F Emissions (tpy)

Source ID	Source Type	PM_{10}	$PM_{2.5}$	Emission Type
001	Stockpiles	16.0	2.1	Fugitive
002	Crusher	0.4	0.1	Point
003	Bins & Loadout	0.2	0.0	Point
004	Mine Ventilation	10.3	1.6	Point
005	Conveyors	0.7	0.1	Point
010	Screening	0.5	0.0	Point

Source ID	Source Type	PM_{10}	$PM_{2.5}$	Emission Type
011	Crushed Limestone	1.0	0.1	Fugitive
Totals	N/A	12.1	1.8	Point
		17.0	2.2	Fugitive

Mobile sources at the facility include underground mining equipment, listed under source classification code 2270009010, above ground construction equipment identified under SCC 2270002000, as well as light duty gasoline trucks and light and heavy-duty diesel trucks. The underground mining mobile sources are specialized equipment designed to function in the unique environment of an underground mine. Above ground mobile sources would include heavy construction equipment used for material handling and stockpile management. To develop appropriate emissions estimates for the mobile sources, the BLM utilized USEPA's Nonroad Model to generate social cost of carbon (SCC)-specific emissions factors (grams per horsepower-hour) for Colorado. The BLM used estimated thermal efficiencies of the equipment engines along with the fuel data from the mine to provide for the overall emissions estimates.

Mine ventilation CH_4 emissions are calculated based on CH_4 concentration, air flow through the average ascent speed (VAM) and density. As stated above, 0.2 percent CH_4 is assumed. Airflow is 296,269 cubic feet (ft) per minute (converted to standard flow 227,742 standard cubic ft (scf) per minute). The density of CH_4 is 0.042 lb/scf Total CH_4 emissions are 1.91 lb/min.

The three emergency generators operate 500 hours per year (3,251 horse power [hp] Cummins unit) or 250 hr/yr (225 hp Baldor and O'Brien). All emission factors associated with the Cummins generator are EPA Tier 2 standards. The other two assumed AP-42 emission factors (EPA 1996, Section 3.3, Table 1). All factors are in units of lb/hp-hr. The King II Mine also utilizes one other propane fueled combustion units. Calculations assumed a total of 1,698.5 gallons per year of propane (average annual usage between 2011 and 2012). AP-42 Table 1.5-1 (EPA 2008) is used with factors of lb/10^3 gal. Total miscellaneous equipment includes the aggregation of emergency generators and the propane unit. **Table 2.2-10** summarizes the direct emissions estimated from permit exempt stationary and mobile sources for the Proposed Action. These emissions were correlated to an annual maximum coal production rate of 800,000, 1.1 million, and 1.3 million tons.

Table 2.2-10 Unpermitted Source Emissions (tpy)

Source	PM_{10}	$PM_{2.5}$	CO	NO_x	VOC	SO_2	CO_2	CH_4	N_2O
	800,000 Tpy								
Mine Ventilation (VAM)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	640	N/A
Misc. Mobile Equip.	0.50	0.50	6.41	13.17	0.84	0.17	1,296	0.06	0
Underground Mining Equipment (mobile)	1.50	1.46	2.30	8.87	10.54	0.15	666	0.04	0.01
Surface Mining Equipment (mobile)	0.36	0.34	0.43	2.30	4.93	0.08	359	0.01	0.01
Totals	2.35	2.30	9.15	24.35	16.30	0.39	2,320	640	0.03

Source	PM_{10}	$PM_{2.5}$	CO	NO_x	VOC	SO_2	CO_2	CH_4	N_2O
	1.1 million tpy								
Mine Ventilation (VAM)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	880	N/A
Misc. Mobile Equip.	0.68	0.68	8.82	18.11	1.16	0.23	1,782	0.09	0.00
Underground Mining Equipment (mobile)	2.07	2.01	3.17	12.20	14.49	0.21	915	0.05	0.02
Surface Mining Equipment (mobile)	0.49	0.47	0.60	3.17	6.77	0.11	494	0.02	0.02
Totals	3.24	3.17	12.58	33.48	22.42	0.54	3,190	880	0.04
	1.3 million tpy								
Mine Ventilation (VAM)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1040	N/A
Misc. Mobile Equip.	0.81	0.81	10.42	21.41	1.37	0.27	2,105	0.10	0.00
Underground Mining Equipment (mobile)	2.44	2.38	3.74	14.42	17.12	0.25	1,082	0.06	0.02
Surface Mining Equipment (mobile)	0.58	0.56	0.70	3.74	8.00	0.12	583	0.02	0.02
Totals	3.83	3.74	14.87	39.56	26.49	0.64	3,770	1,041	0.04

[1] The VAM is hardwired; therefore, there are no direct emissions from the VAM other than the CMM.

2.2.2.2 Low Cover Crossing

A low cover crossing (LCC) is to be constructed as part of the Proposed Action, which is currently located within the existing OSMRE permit area. Refer to the EA for further details regarding the crossing description and location. The following outlines potential air quality emissions associated with the construction of the crossing.

Construction emissions consist of four constituents, which are: on-road vehicle exhaust, off-road vehicle exhaust, fugitive dust from commuting traffic, and general construction. Both vehicle exhaust components are derived the EPA mobile source model, MOVES. The former EPA NONROAD has been incorporated into MOVES to account for all construction tailpipe emissions. **Table 2.2-11** provides all the anticipated construction vehicles to be utilized. In association with the vehicles, there is expected to be three commuter vehicles each work day traveling 129 miles (207.6 km). The total disturbed area is 20 acres and the total excavated material is 248,888 cubic yards. Lastly, fugitive dust control would use water and magnesium chloride as a chemical suppressant. The 2015 Utah Department of Air Quality Guidelines suggest that use of suppressant and watering equates to 85 percent control of fugitive dust (UDAQ 2015).

Table 2.2-11 Construction Equipment List

Source	hp	Number of Each	Daily hours	Total Weeks[1]
Excavator	240	2	10	28
Front End Loader	541	1	10	28
Haul Truck	474	2	10	28
Water Truck	230	1	10	28
Dozer	450	1	10	28
Skid Steer	100	1	10	28

[1]All data supplied by GCCE and each work week is assumed to consist of 5 days.

Construction is expected to last 140 days. The EPA's 1999 final report on Estimating Particulate Emissions from Construction Operations identifies several methods for determining emissions (EPA 1999). Given the knowledge of the LCC, a Level 2 assessment to calculate emissions was used. The total amount of earth moved (248,888 cubic yards), Project Area (20 acres) and duration (140 days) are all known. Therefore, the following PM_{10} emission factors were applied: 0.011 ton/acre/month plus 0.059 ton/1,000 cy. It was assumed that only on-site cut and fill is performed. Given the 85 percent control and a 10 percent $PM_{2.5}/PM_{10}$ ratio as provided by EPA AP-42, Section 13.2, fugitive construction particulate emissions were calculated. **Table 2.2-12** illustrates that the total emissions associated from the LCC are quite low and would have minimal impact on the surrounding area.

Table 2.2-12 LCC Summary Emissions (tpy)

Pollutant	Off-road Exhaust	Commuting Exhaust	Paved Road Fugitive Dust	General Const. Fugitive Dust	Total
CO	2.18	0.19	NA	NA	2.4
NO_x	4.60	0.02	NA	NA	4.6
PM_{10}	0.31	0.0003	2.65E-03	2.28	2.6
$PM_{2.5}$	0.31	0.0002	6.49E-04	0.23	0.5
SO_2	0.01	0.0001	NA	NA	0.0
VOC	0.62	0.003	NA	NA	0.6
CO_2	1609.6	20.4	NA	NA	1630.0
CH_4	89.86	0.001	NA	NA	89.86
N_2O	40.99	0.0003	NA	NA	40.99

The indirect emissions would have an impact on the region as all the coal extracted from the mine would be burned at the various cement plants, which currently operates nearly 100 percent of their fuel on coal from the King II Mine.

Table 2.2-13 outlines the combined direct annual emissions given a coal production rate of 1.3 million tons and total direct Project lifetime emissions from 17 million tons produced. This is derived from a mine life of 22 years with 19 years at the annual production of 800,000 tons and the remaining three at 600,000 tons.

Table 2.2-13 Total Project Emissions

Source	PM_{10}	$PM_{2.5}$	CO	NO_x	VOC	SO_2	CO_2	CH_4	N_2O
Annual Unpermitted Sources	3.83	3.74	14.87	39.56	26.49	0.64	N/A	N/A	N/A
Annual Permitted Sources[1]	29.10	4.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low Cover Crossing	2.6	0.5	2.4	4.6	0.6	0.01	N/A	N/A	N/A
Annual Total[2]	35.53	8.24	17.27	44.16	27.09	0.65	N/A	N/A	N/A
Lifetime Unpermitted Sources	N/A	N/A	N/A	N/A	N/A	N/A	49,304	13,606	0.54
Lifetime Permitted Sources	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low Cover Crossing	N/A	N/A	N/A	N/A	N/A	N/A	1,630	89.86	40.99
Lifetime Total[2]	N/A	N/A	N/A	N/A	N/A	N/A	50,934	13,696	41.53

[1] The permitted emissions include both point and fugitive sources and annual emissions that were derived from the CDPHE permit that allows 1.3 million tons production as shown in **Table 2.2-9**.

[2] GHG emissions are considered longer term pollutants than annually because they tend to stay in the atmosphere for much longer periods of time. Criteria pollutants are assessed on an annual because of shorter averaging period standards. The "N/A" are added to reflect the varying timeframes.

2.2.2.3 Indirect Emissions

Indirect air emissions from the Proposed Action were estimated for activities that are reasonably foreseeable and include; coal transport (where a destination within the USA and quantity of delivered coal is known), mine worker commutes, and downstream coal combustion.

Downstream Emissions

GCCE supplies approximately 193,100 tons of coal to two cement kilns and two narrow gauge railroads directly, while the remainder of the coal is sold (via the Gallup, NM rail terminal) to GCC cement plants in Mexico (240,000 tpy) and to variable cement facilities in Arizona and Texas. Both cement kilns operate under state issued air permits, and both facilities are subject to Title V permitting requirements (i.e., they are classified as major stationary sources).

The GCC Rio Grande Pueblo Plant (**Table 2.2-14**) has a permit (#98PB0893) condition that limits annual firing fuel (coal and tire derived fuel [TDF]) to no more than 198,418 tons on a rolling 12-month basis. The King II Mine currently supplies 105,000 tons of coal annually (approximately 53 percent by weight) to the

facility and expects this to remain constant going forward. The facility also has additional 12-month rolling fuel use limits for pipeline quality natural gas and propane of not more than 381,373 one million British Thermal Units. The cement kiln itself is subject to a multitude of control technologies and monitoring required under maximum achievable control technology LLL (the maximum achievable control technology for Portland cement manufacturing). For the purposes of this analysis, the agencies assume that the 53 percent primary fuel stock supplied by the King II Mine is an appropriate surrogate for permitted emissions at the Pueblo facility. The King II Mine coal feeds the kiln, and it is reasonable to delineate the total site emissions required to support the kiln operations as attributable to the coal itself because no other sources of coal are sent to Pueblo at this time and that is not expected to change in the future. The differences in the fuel compositions used at the Pueblo facility would provide for varying emissions profiles. The available literature suggests that on average TDF can provide for lower particulate matter emissions on an energy density basis. None of the other criteria pollutants were shown to have a statistically significant difference for TDF firing vs. traditional fuels (including coal). The agencies note that some of the literature suggests that CO_2 emissions from TDF would be reduced by 8 to 20 percent compared to traditional fuels. However, for this analysis the range of potential reductions (from tire types and computational methods) and equipment and firing practices associated with using TDF in the literature is highly variable and thus too speculative to support any further delineation of emissions at the Pueblo facility (TDF 2017). Where the literature suggests a pollutant would be solely attributable to coal, that value will be disclosed (e.g., Hg).

Table 2.2-14 Pueblo Facility King II Emissions (tpy)

Source	PM_{10}	$PM_{2.5}$	CO	NOx	VOC	SO_2	CO_2e[1]	Hg (lb/yr)
Facility	221	217	588	604	52	505	735,230	25

[1]CO_2e emissions are based on 2017 EPA FLIGHT reported emissions

The GCC Rio Grande Tijeras Plant (**Table 2.2-15**) has similar operations to that of the Pueblo facility and is covered under NM Title V permit #532. The permit and underlying construction permits provide for all the same source requirements (controls and monitoring) as the Pueblo facility and is publicly available from the Albuquerque Environmental Health Department for review.

Table 2.2-15 Tijeras Facility King II Emissions (tpy)

Source	PM_{10}	$PM_{2.5}$	CO	NOx	VOC	SO_2	CO_2e[1]	Hg (lb/yr)
Facility	135	66	790	772	79	21	306,846	10

[1]CO_2e emissions are based on 2017 EPA FLIGHT reported emissions

Unlike the Pueblo facility, the Tijeras kiln is fired entirely on coal (a minor amount of natural gas is used for startup) and the kilns themselves do not appear to have a fuel throughput limits, but rather performance-based clinker production limits (33.7 tons/hour). Similarly, the permit does not contain explicit limits for GHG and mercury emissions but does provide for mercury monitoring requirements and performance-based standards. Facility GHG emissions were obtained from the USEPA's Facility Level GHG Tool (FLIGHT) for 2016. The data and methodology (subpart C, equation C-2a) that GCC utilized to report

the facility's GHG emissions allowed for back calculating the total coal throughput for the facility and the total clinker produced for the reporting year. The facilities reported 2014 criteria emissions was obtained from USEPA's inventory database to use as correlation parameters and provide for the upper level of emissions that the shipped Proposed Action coal would produce from the facility. To estimate the mercury emissions, the BLM multiplied the 2014 production data (derived from FLIGHT metrics) by the permit listed performance standard of 55 pounds (lbs) of mercury per MM- tons of clinker produced. All the 2014 emissions were corrected to account for the variance between the report year, and Proposed Action coal use levels.

2.2.2.4 Cement Production

The chemical reactions involved in the manufacture of clinker inherently produce or liberate CO_2 in the process. Unfortunately, USEPA's FLIGHT data only provides speciated data for the Tijeras facility. The Pueblo facility is monitored by CEMS (continuous emissions monitoring system) as a single stream and would therefore include both the combustion and reaction related emissions. For the purposes of disclosure, calcification emissions are presented for both facilities relative to the Tijeras facility given that the chemistry for clinker production is mostly equivalent regardless of where it is produced. The total CO_2 emitted from the calcification reaction is estimated to be 697,393 tons based on the relative production rates that the 181,000 tons of Proposed Action coal shipments (delivered to Pueblo and Tijeras) would provide in the maximum year.

2.2.2.5 General Combustion

This analysis assumes that the remaining portion of the maximum year coal to be shipped (879,040 tons) from the King II Mine is eventually combusted. Approximately 5,100 tpy is combusted in two regional narrow-gauge railroads. The remainder would be combusted in well controlled facilities, but potentially anywhere in northern Mexico and in the southwestern U.S. As can be clearly seen from the differences in the two GCC Rio Grande facilities detailed above, different plant configurations, locations, permitting authorities, age, etc., can have vastly different emissions for a relatively similar quantity of the same fuel. Given that the agencies have no way of knowing where King II Mine coal would be combusted from year-to-year, or in what quantities (except for coal delivered directly to GCC owned cement plants in Tijeras, and Pueblo) we are not providing any other criteria or HAP emissions estimates from specific locations in the southwestern U.S.

Additionally, there currently is not a reliable method for producing emissions inventories of criteria pollutant from residential coal combustion. The available emissions factors from EPA assume larger industrial facilities that employ a variety of firing practices and are typically well controlled. It is reasonable to assume that the rail and residential unit are simple stoker fired and are not controlled. The minor quantities of coal utilized by these sources is not expected to contribute to localized impacts to air quality, especially from the rail sources where emissions are spread out along the length of the line (tracks) in what is assumed to be a linear or uniform fashion. Further these emissions are temporally dispersed, such that they would not accumulate for a given unit of time in any one area like stationary source emissions could under certain meteorological conditions. However, coal analysis data was received that allowed for the estimation of mercury emissions for the Durango Silverton and Chama Narrow Gauge Rail Roads. The

analysis data shows that the mercury emissions from the anticipated coal combustion would be 0.28 and 0.12 lbs/yr for each railroad respectively.

However, reasonable estimates of GHG's can be produced from these sources (**Table 2.2-16**) given that there are far fewer parameters that affect those emissions compared to the criteria and HAPs. To provide for these estimates, the GHG emissions factors published by USEPA for use in their GHG reporting regulations were used (USEPA 2014). Additionally, the estimated calcination CO_2 emissions for the balance of the coal that is assumed to be combusted in other cement production facilities (approximately 880,940 tpy). For this calculation the derived emissions factor from the Tijeras facility was used (from examination of EPA's FLIGHT data, metric tons of CO_2 per metric tons of clinker produced ~ 0.33). This was necessary due to the uncertainty of the fraction of lime contained in other facilities feedstocks, where the amount of lime directly affects the ratio of CO_2 liberated during production. Because the efficiency with which these other facilities can produce clinker from the amount of coal consumed, the coal to clinker ratio from the Tijeras facility was used to provide an approximate estimate. Again, this was necessary because the agencies do not know how much clicker these other facilities, within the USA, produce to allow the derived emissions factor to be applied directly.

Table 2.2-16 Remaining Coal Combustion King II Mine Emissions (tpy)

Source	CO_2	CH_4	N_2O	CO_2e[1]
Facility	4,795,915	184,259	26,801	17,389,088

[1]GWPs used from 40 CFR Part 98 Subpart A, Table A-1

2.2.3 Direct Air Quality Effects

The region surrounding the Proposed Action area is currently designated as attainment for all criteria pollutants. The attainment designation means that no violations of ambient air quality standards have been documented in the area. Air quality effects are measured by determining whether the area would continue to be in attainment or not.

A detailed air quality assessment of the mine was conducted by APCD to support permitting of the King II Mine at currently authorized production rates. According to APCD staff, the mine was not required to provide any dispersion modeling to support their application since their allowable emissions are so low (BLM and OSMRE 2017).

The King II Mine is primarily a source of PM_{10} emissions. More so than other pollutants, PM_{10} is a localized pollutant where concentrations can vary considerably. The proximity of any receptor to the mine and the area's topography between the mine and receptor would greatly influence the level of air quality impacts associated with PM_{10}. Design Feature 1a described in the 2017 Federal Coal Lease Modification and Federal Mine Permit Revision outlines the measures implemented by GCC to minimize direct PM_{10} emissions from mine facilities.

With respect to potential O_3 formation, the mine is not a significant source of precursors (NO_X and VOC). When compared to the NEI, precursor totals for LPC in 2014 shown in **Table 2.2-4** above, the mine's emissions represent only 0.3 and 0.1 percent of the NO_X and VOC emissions respectively (excluding

biogenic emissions from the NEI). Given that the mines precursor emissions are so low 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 any regional O_3 formation potential. However, the BLM did analyze O_3 culpability all the mines that produce federal minerals in Colorado cumulatively, via the Colorado Air Resources Management Modeling study (CARMMS). The CARMMS model, the analysis scenarios, and results are all described in the cumulative impacts section below. The CARMMS model was also used to assess $PM_{2.5}$ impacts (including secondary formation) from the mines producing federal minerals in Colorado.

Where a PSD source is located near a Class I airshed (within 30 miles [48.3 km]) the AQRVs thresholds set by the applicable Class I controlling agency must be assessed to determine if an adverse impact on the area is likely to occur. Although the King II Mine is within 30 miles (48.3 km) of two Class I areas, it is not a major PSD source. The King II Mine is classified as minor source of emissions, and according to CDPHE it was not required to provide any air modeling to support its permit application. Given that the mine has very low emissions of AQRV impacting pollutants and that the primary pollutant of concern (particulate matter) is a highly localized pollutant (due to gravitational settling and topological impaction), any potential Class I area impacts are expected to be minor, with respect to direct impacts. The CARMMS analysis did consider AQRV impacting pollutants, which are discussed in **Section 2.2.7** Cumulative Impacts.

The miscellaneous facility equipment would be the only stationary sources to generate HAP emissions at the mine. The total HAP emissions from all sources at the mine is approximately 6.1 tons and is based on the ratio of HAPs to VOC in EPA's NEI data for Non-Road Diesel Equipment for LPC. These source types represent most of the VOC emissions generated by the mine (see **Table 2.2-10**). A majority of the mine's HAP emissions (68 percent) would be exhausted through the mine shaft ventilation system (this is true for the equipment's criteria emissions as well), and 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 EPA (EPA 2016) provides Regional Screening Level values for diesel emissions (as a whole); including a Reference Concentration, 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 ($5\mu g/m^3$). Given the minor magnitude of these emissions (including the rate they could be expected to be emitted, about 0.5 grams per second cumulatively across the facility—total HAP grams divided by 3,000 operating hours (assumed minimum), divided by 3600 seconds per hour), and the overall dispersion expected to occur within the facility prior to reaching a fence line, it is highly unlikely ambient air quality would be impacted to a degree that the public (for which the nearest potential receptor is about a 0.5 mile [800 meters] away) would experience an elevated exposure risk based on EPA's exposure assessment guidelines. Therefore, impacts associated with HAP emissions would be negligible and short term.

According to the U.S. Global Change Research Program (2009), global warming is unequivocal, and the global warming that has occurred over the past 50 years is primarily human caused. Standardized

protocols designed to quantify climatic impacts that result from specific emissions, are presently unavailable. Therefore, impact assessment of specific impacts related to anthropogenic activities on global climate change cannot be accurately estimated. Moreover, specific levels of significance have not yet been established by regulatory agencies. Therefore, climate change analysis for this EA within this air quality section is limited to accounting for GHG emissions changes that would contribute incrementally to climate change. Qualitative and quantitative evaluations of potential contributing factors are included where appropriate and practicable.

The Office of Natural Resources Revenue, U.S. Department of the Interior data shows that in 2017 total federal (onshore) production of coal in the country stood at approximately 326,073,802 tons. As a whole (federal and non-federal), the U.S. produced approximately 774,609,357 tons of coal in 2017 (U.S. Energy Information Administration). Federal coal made up approximately 42.1 percent of the total 2017 production, and in general has continued to decline along with the total coal production nationally. On an annual basis, the maximum production year for the Proposed Action (800,000 – 1.3 million tons) would represent a range of 0.24 – 0.40 percent of all federal coal produced nationally and 0.10 - 0.17 percent of all the coal produced in the U.S. relative to 2017. The total direct and estimated indirect GHG emissions from the maximum projected King II Mine production (based on annual emission estimates) would be approximately 0.28 percent of the total U.S. emissions relative to 2016, and 0.038 percent of the total global GHG burden relative to 2014 on a worst-case year annualized basis.

Regardless of the accuracy of emission estimates, predicting the degree of impact any single emitter of GHGs may have on global climate change or on the changes to biotic and abiotic systems that accompany climate change, is not possible at this time. As such, the controversy as to what extent GHG emissions resulting from continued mining may contribute to global climate change, as well as the accompanying changes to natural systems cannot be quantified or predicted. The degree to which any observable changes can, or would be, attributable to the Proposed Action cannot be reasonably stated at this time. Given the cumulative nature of the GHG and climate change issue, and a lack of Project specific impacts, please see the cumulative section below for a general description of anticipated changes and impacts.

2.2.4 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, 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." Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under EO 12866 February 2010 (withdrawn by EO13783). 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 to project-level NEPA analyses.

The decision was made not to expand the use of the SCC protocol for this Dunn Ranch Area LBA and Mining Plan Modification for several reasons. Most notably, this action is not a rulemaking for which the SCC protocol was originally developed. Second, on March 28, 2017, the President issued EO 13783 which, among other actions, withdrew the Technical Support Documents upon which the protocol was based and disbanded the earlier Interagency Working Group 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 OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 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 Project decisions, so there is no EO requirement to apply the SCC protocol to Project decisions.

Further, NEPA does not require a cost-benefit analysis (40 C.F.R. § 1502.23), although NEPA does require consideration of "effects" that include "economic" and "social" effects. 40 CFR 1508.8(b). Without a complete monetary cost-benefit analysis, which would include the social benefits of the proposed action to society as a whole and other potential positive benefits, inclusion solely of an SCC cost analysis would be unbalanced, potentially inaccurate, and not useful in facilitating an authorized officer's decision. Any increased economic activity, in terms of revenue, employment, labor income, total value added, and output, that is expected to occur with the proposed action is simply an economic impact, rather than an economic benefit, inasmuch as such impacts might be viewed by another person as negative or undesirable impacts due to potential increase in local population, competition for jobs, and concerns that changes in population would change the quality of the local community. Economic impact is distinct from "economic benefit" as defined in economic theory and methodology, and the socioeconomic impact analysis required under NEPA is distinct from cost-benefit analysis, which is not required.

Finally, the SCC protocol does not measure the actual incremental impacts of a Project on the environment and does not include all damages or benefits from carbon emissions. The SCC protocol estimates economic damages associated with an increase in CO_2 emissions - typically expressed as a one 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 arrived at 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 for Project level analyses. For example, in a recent environmental impact statement, OSM estimated that the selected alternative had a cumulative SCC ranging from approximately $4.2 billion to $22.1 billion depending on dollar value and the discount rate used. The cumulative SCC for the no action alternative ranged from $2.0 billion to $10.7 billion (OSMRE 2015). Given the uncertainties associated with assigning a specific and accurate SCC resulting from 22 additional years of operation under

the mining plan modification, and that the SCC protocol and similar models were developed to estimate impacts of regulations over long time frames, this analysis quantifies direct and indirect GHG emissions and evaluates these emissions in the context of U.S. and global GHG emission inventories as discussed in **Section 2.2.7**.

To summarize, this analysis does not undertake an analysis of SCC 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; and 4) the full social benefits of coal-fired energy production have not been monetized, and quantifying only the costs of GHG emissions but not the benefits would yield information that is both potentially inaccurate and not useful.

2.2.5 Mitigation

There would not be any mitigation necessary for air and climate resources.

2.2.6 Cumulative Actions and Effects

2.2.6.1 CARMMS Projected Impacts

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. The cumulative impacts to air quality in the King II Mine area would result primarily from emissions of $PM_{2.5/10}$ from the current and future activities occurring within the region such as agriculture, ranching/grazing, and vehicle traffic.

To examine potential cumulative air quality impacts from activities that it authorizes, BLM initiated the CARMMS. 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 assumes current development practices and existing emissions controls required by regulations (Environ 2017).

The CARMMS project leverages the work completed by the WestJumpAQMS, and the base model platform configuration (CAMx), meteorology Weather Research Forecasting (WRF), and model performance metrics are based on those products. The complete report and associated data are available on our website at: https://www.blm.gov/documents/colorado/public-room/data. The CARMMS model domain has a minimum grid resolution of 2.5 miles (4 km).

Because 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, the 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. 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)

The study provided for a single mining scenario based on each mine maximum allowable emissions rate, which were estimated based on the CDPHE APEN database and available EISs and EAs prepared for previous authorizations. We note that most mines in Colorado are not currently producing at their maximum (i.e., what CARMMS analyzed) authorized capacities. EPA default chemical speciation profiles were used in the SMOKE emissions modeling for mining except that the EPA mining $PM_{2.5}$ speciation profile was adjusted for abnormally high sulfur emissions that were erroneous for typical underground mining operations. The modelled emissions details are provided in the CARMMS report as defined in Appendix D and D-1 (Environ 2015).

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.

The results (**Figure 2.2-2**) show that 24-hr $PM_{2.5}$ 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 2.5 miles (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 King II Mine facility (not more than 0.4µg/m^3 for PM_{10} and 0.2µg/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 does not include CMM VOCs since they are unknown.

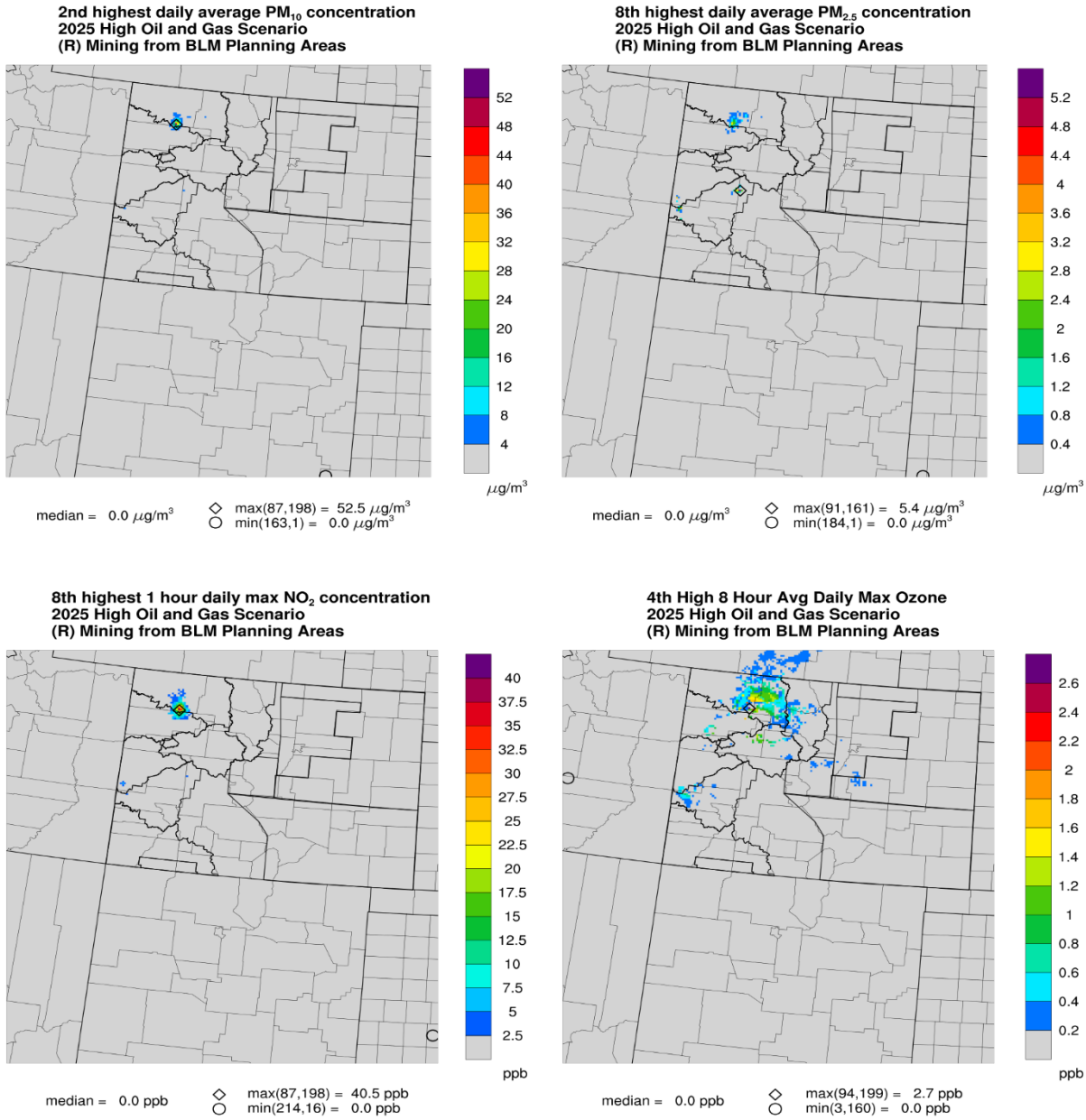


Figure 2.2-2 Contribution to the 2025 High Oil and Gas Scenario (R) Mining from BLM Planning Areas (Environ 2017)

The CARMMS data suggests that the overall air quality impact surrounding the mine is essentially negligible when compared to other potential sources in the state of Colorado.

For the TRFO, we are disclosing the high CARMMS scenario (**Figure 2.2-3**) to account for all the reasonably foreseeable future actions that could occur within the area (mostly oil and gas development), while noting that the area is currently tracking far below the low scenario.

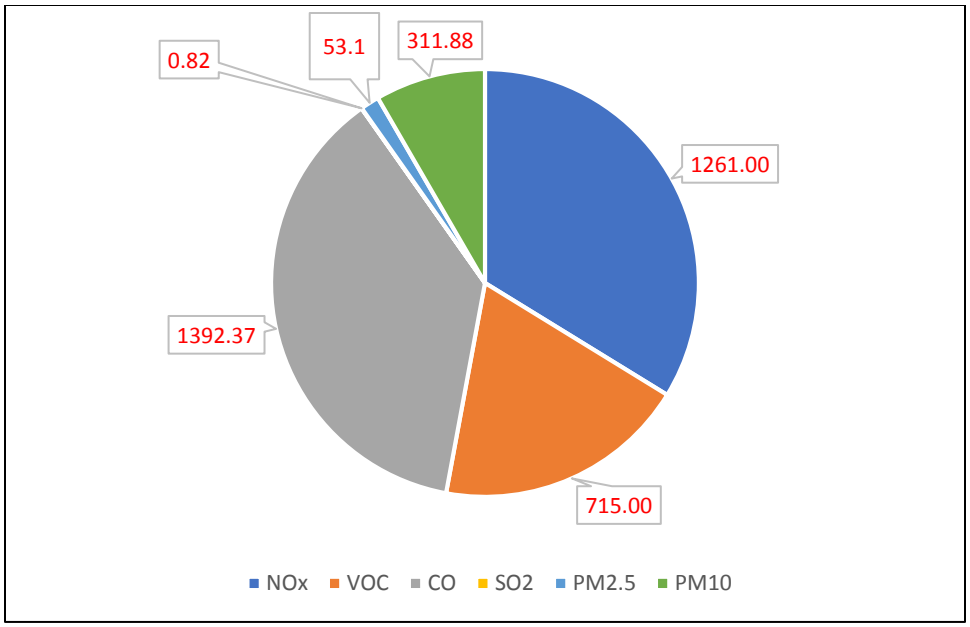


Figure 2.2-3 CARMMS 2025 TRFO Federal High Oil and Gas Scenario Emissions tpy (Environ 2017)

The high scenario oil and gas development emissions are large enough to account for all of the reasonably foreseeable activities outlined in the CARMMS report that have significant emissions generation potential (refer to **Figure 2.2-4**).

As can be seen in the source apportionment results, the impacts are mostly the result of development in and proximate to the Gothic Shale Play area. The King II Mine has far fewer NO_X and VOC emissions than that of the high oil and gas scenario, such that the mine itself would not be expected to contribute significantly to direct O_3 formation. Several other data metrics produced by CARMMS to describe potential impacts to sensitive resources are disclosed in **Table 2.2-17** below.

Table 2.2-17 Maximum Source Group Contributions Mines and TRFO High Oil and Gas Scenarios (H & R)

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 Mines (Class I Area)	0.6034	1	0	0.0581	Flat Tops	0.2071	0.0287
TRFO O&G (Class I Area)	0.0407	0	0	0.0062	Weminuche	0.0666	0.0134
CO Mines (Class II Area)	0.6442	2	0	0.1730	Dinosaur NM	0.2071	0.0287
TRFO O&G (Class II Area)	0.0886	0	0	0.0133	S. San Juan	0.0666	0.0134

dv = deciviews
kgN = kilograms of nitrogen
ha = hectares

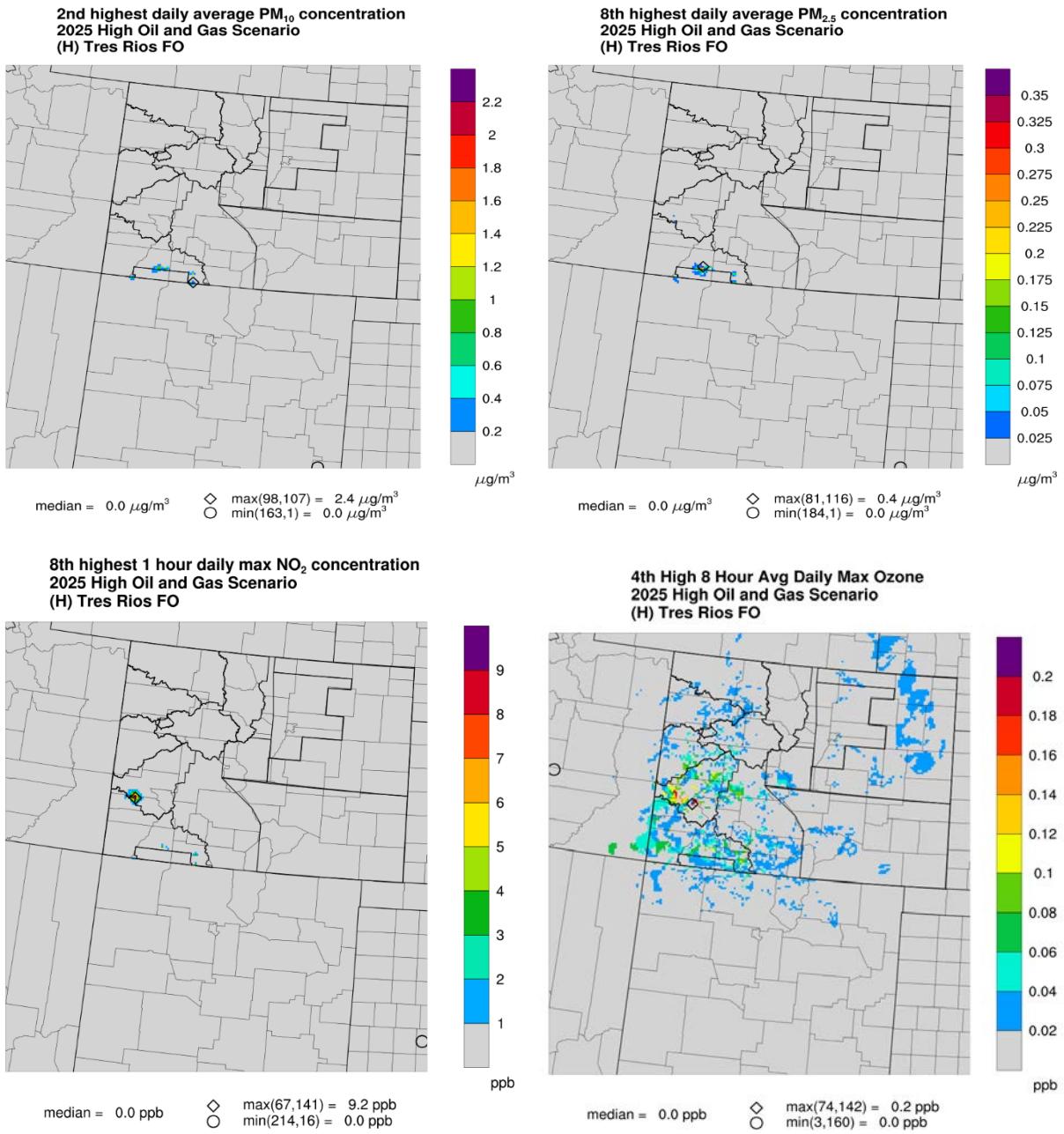


Figure 2.2-4 Contribution to the 2025 High Oil and Gas Scenario (H) Tres Rios Field Office (Environ 2017)

As would be expected given the plots above, the Colorado Mines (particularly the surface mines) contribute greatly to the PM related NAAQS and visibility impacts. Although the exact King II Mine contributions cannot be teased out of the data, it's highly unlikely that the mines emissions contribute a significant fraction of the modeled AQRV impacts shown above, given the isolation of the facility in relation to the impacted area and the localized nature of the PM emissions.

For the total cumulative results (rolled up source apportionment and total model outputs), the BLM is disclosing the high CARMMS scenario. **Figure 2.2-5** below shows the tracked report year (2017) federal oil and gas development emissions contrasted to each CARMMS scenario, where the emissions levels of each pollutant are shown relative to the high scenario (i.e., the high scenario is 100 percent on the graph). In most cases the 2015 emissions are far below the low CARMMS scenario, such that this has been deemed the appropriate scenario to disclose given the likelihood or potential for emissions generating activities to exceed the 2025 estimates in the short term. As noted above, the mining emissions were held constant in all future year scenarios such that those impacts are static regardless of the CARMMS oil and gas scenario.

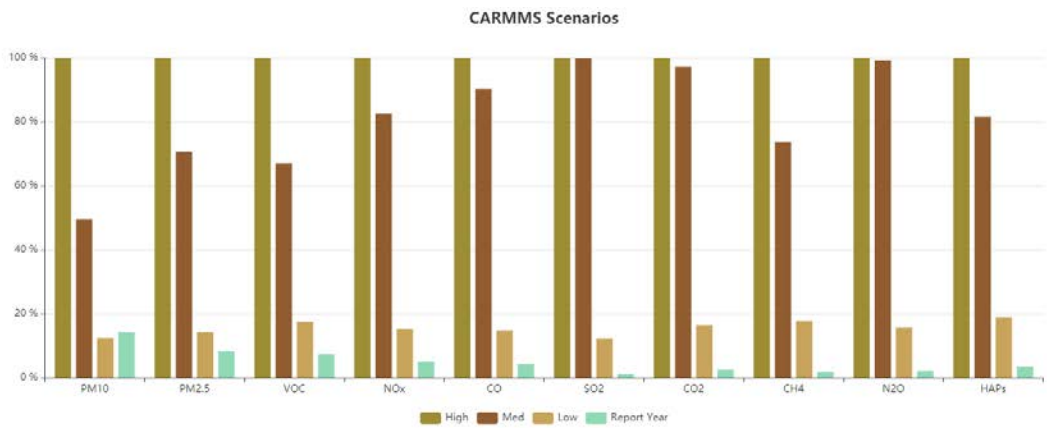


Figure 2.2-5 CARMMS BLM CO Cumulative Oil & Gas Tracking (Federal)

As shown in **Figure 2.2-6**, it is evident that 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 that these maximums are not necessarily relative to any exceedance values that may have been modeled for a pollutant shown (**Table 2.2-18**).

Table 2.2-18 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

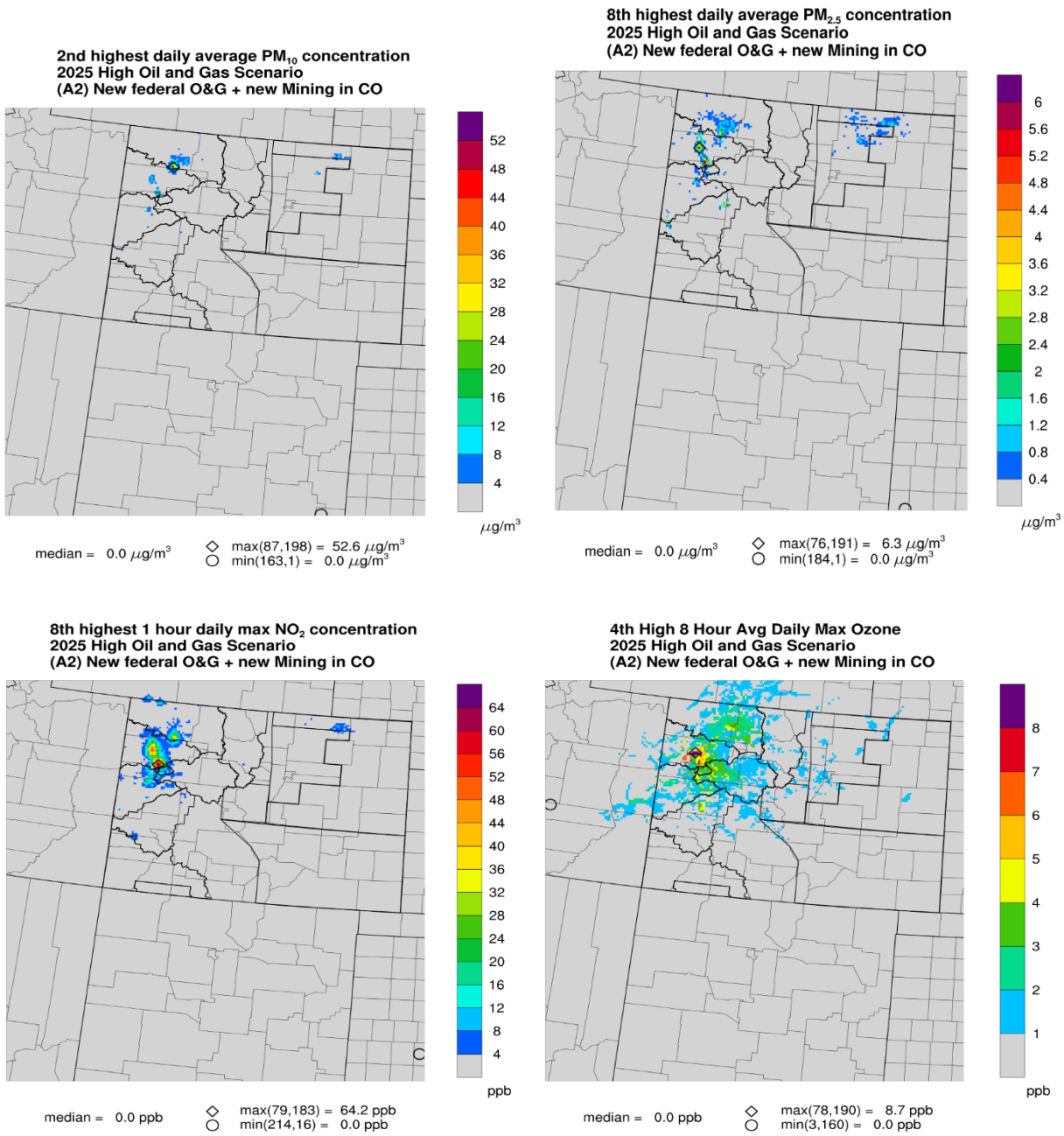


Figure 2.2-6 Contribution to the 2025 High Oil and Gas Scenario (A2) New Federal O&G and Mining (Environ 2017)

The plots in **Figures 2.2-7** and **2.2-8** 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 (undoubtable 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 System photo-chemical models (even in the updated Intermountain West Data Warehouse 2011b platform), for reasons which are currently unknown. Although we suspect the area's topography, especially the rapid elevation gains along the Roan cliffs, along with the limits of the CAMx and WRF meteorological model resolutions may have something to do with it. 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.

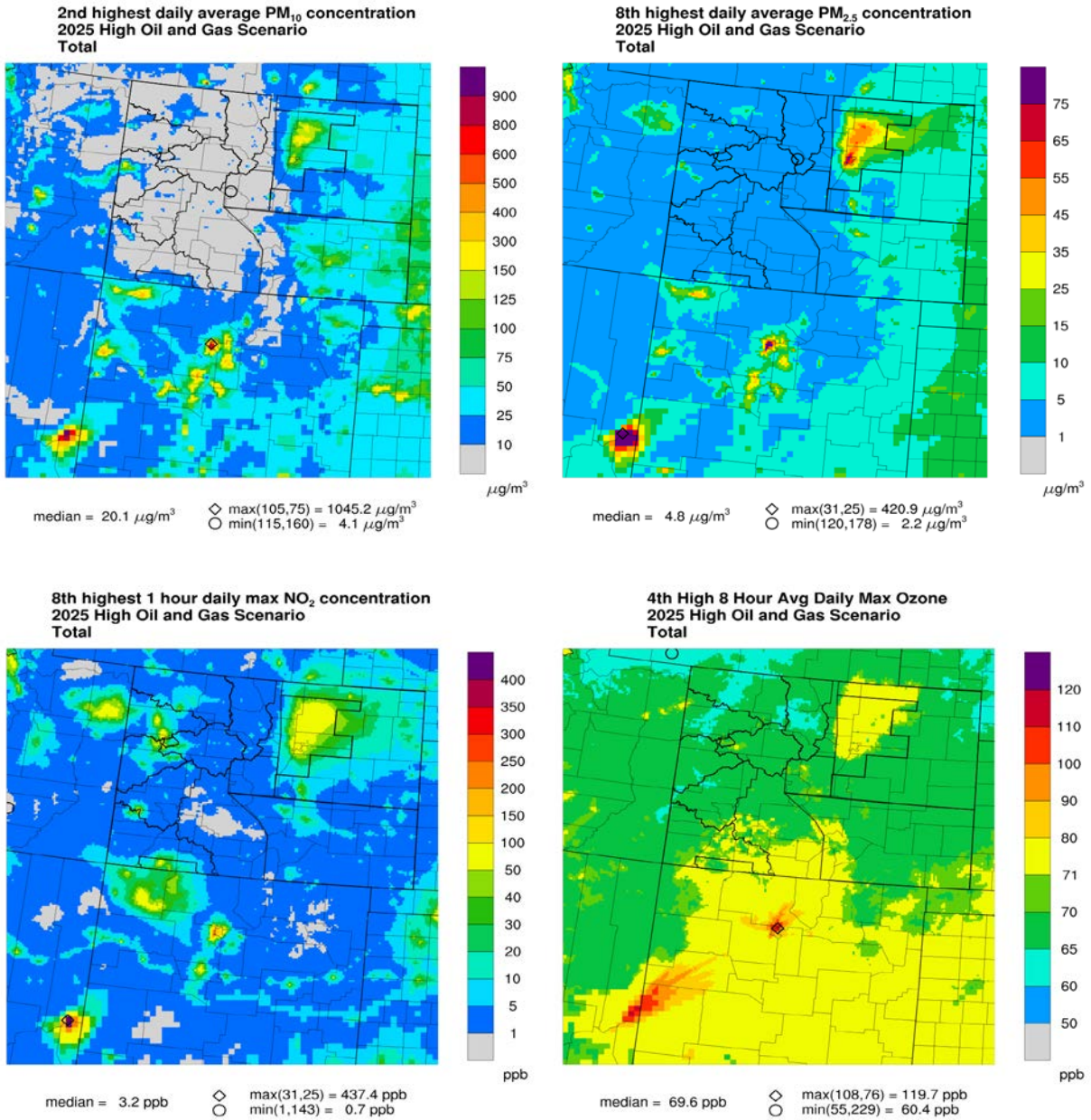


Figure 2.2-7 Total Cumulative Impacts to the 2025 High Oil and Gas Scenario (Environ 2017)

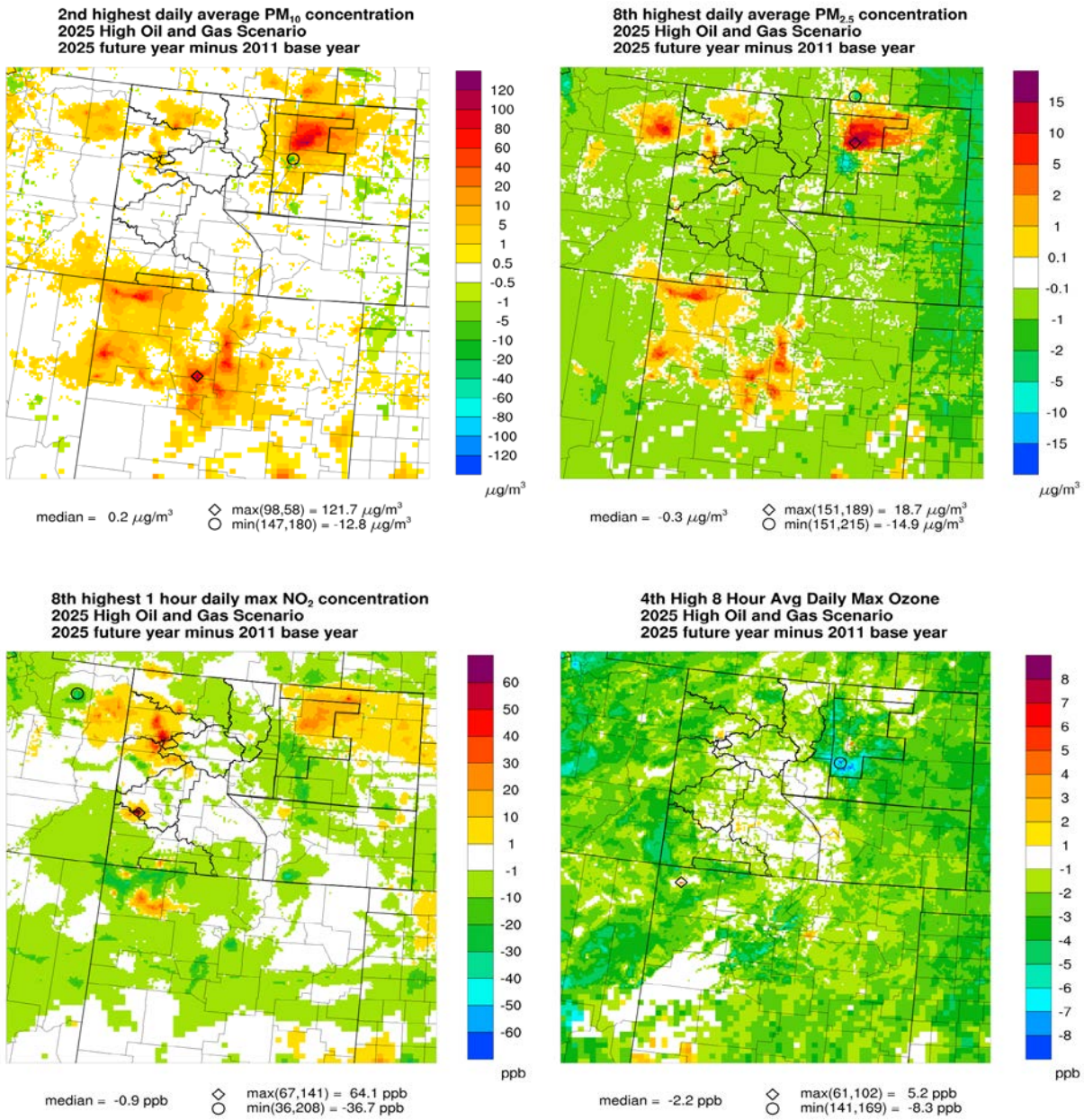


Figure 2.2-8 Cumulative Changes (future minus base) High Oil and Gas Scenario (Environ 2017)

2.2.6.2 Greenhouse Gases and Climate Change

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 radiative forcing that are meant to serve as input for climate and atmospheric chemistry modeling. There are 4 primary pathways that climate scientists have used for assessment in numerous climate models shown in **Figure 2.2-9** and **Figure 2.2-10** and described as follows:

- RCP2.6 - Very low emissions levels leading to peak in radiative forcing at 3.1 W/m^2 by mid-century, returning to 2.6 W/m^2 by 2100, where greenhouse gas 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 radiative forcing stabilizing between 2040 and 2060. This scenario also provides for "negative emissions" starting in 2080, and essentially projects 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 percent per year until 2040, and then continue at a pace of approximately 10 percent per year until the emissions become negative between 2070 and 2080. The cumulative emissions of this pathway are approximately 1,715.7 $GtCO_2e$ (2018 - 2100). CO_2 alone represents 54.2 percent of the total contributing emissions and 81.5 percent of the total CO_2 emissions are attributable to fossil fuel use.

- 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 greenhouse gas emissions. This pathway forecasts 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 radiative forcing. The cumulative emissions of this pathway are approximately 3,728.6 $GtCO^2e$ (2018 - 2100). CO_2 alone represents 67 percent of the total contributing emissions and 98.2 percent of the total CO_2 emissions are attributable to fossil fuel use.

- 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 greenhouse gas 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. The cumulative emissions of this pathway are approximately 5,380.2 $GtCO_2e$ (2018 - 2100). CO_2 alone represents 74.3 percent of the total contributing emissions and 101.1 percent 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 midcentury 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 greenhouse gas concentration levels and radiative forcing of 8.5 W/m^2 in 2100. This pathway assumes 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 - 2100). CO_2 alone represents 72.3 percent of the total contributing emissions and 97.8 percent 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 (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.

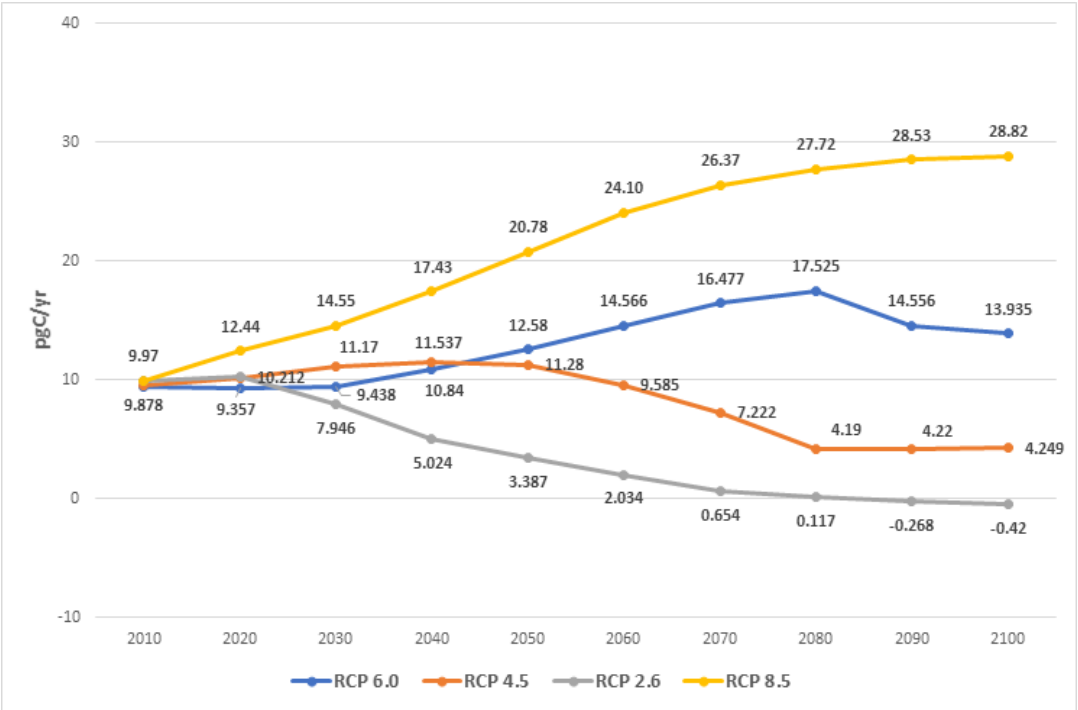


Figure 2.2-9 Global GHG Emissions Projections

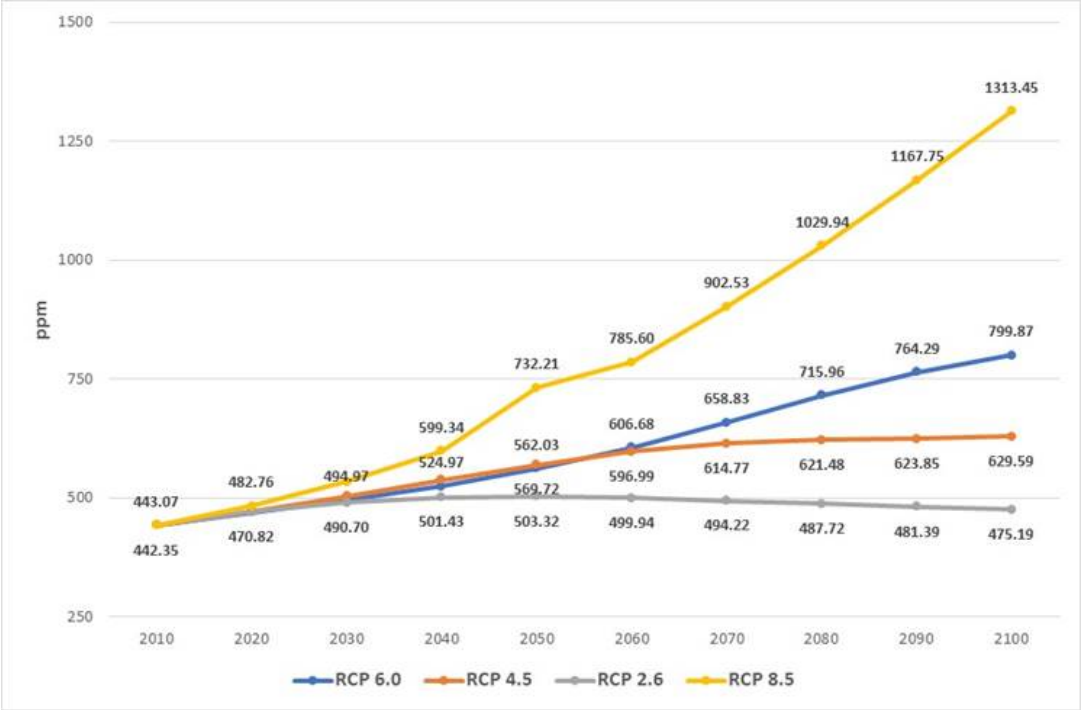


Figure 2.2-10 CO_2e Atmospheric Concentration Projections

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°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 scientist's 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 just how difficult climate analysis is. 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 (net zero), is likely to change over time as emissions trajectories fluctuate and climate science continues to evolve. 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 prior to 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 represent 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 land use changes 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. This value is equivalent to 9.83 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 GtCO2) 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 percent over the next decade to maintain reasonable progress. Recent data from the EPA'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 percent of the global fossil fuel CO_2 emissions on an annual basis (since 2015). In terms of the carbon budget, the annual U.S. emissions are equal to approximately just over 1 percent of the average face value.

According to the Energy Information Administration (EIA) domestic energy production accounts for about 90 percent of all U.S. energy consumption. The three major fossil fuels— petroleum (28 percent), natural gas (31.8 percent), and coal (17.8 percent) —combined accounted for about 77.6 percent of this production, while renewable energy sources (12.7 percent) and nuclear electric power (9.6 percent) 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 has 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 percent annually), and non-hydroelectric 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 percent and -0.2 percent 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 a couple of caveats that data users need to be mindful of. 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 much 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 Bureau to understand the nations 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) is shown in the table below. The coal production data from ONRR was supplemented with data available from the Colorado Division of Mine Reclamation and Safety (DRMS).

According to EIA data, approximately 95 percent of oil stocks in the U.S. are used as a fuel source, while the remainder is typically used to produce petro-chemical products such as plastics and other consumables. The ultimate fate of these transformed petroleum stocks (5 percent) is unknown beyond the basic facts that some of it will be recycled, landfilled, and potentially combusted in waste-to-energy facilities. The latter component is an exceptionally small portion of energy production in the U.S. (0.4 percent, EIA 2015), and thus for the purposes of this report we assume a 95 percent combustion rate for oil production. Natural gas stocks are typically used as an energy source (via combustion) in the broader part of the economy. The industrial sector also uses natural gas as a raw material to produce chemicals, fertilizer, and hydrogen. The industrial sector accounts for about 35 percent of U.S. natural gas consumption, and natural gas was the source of about 31 percent of the U.S. industrial sector's total energy consumption (EIA 2017). The data suggests that 4 percent of natural gas stocks are diverted to non-combustion activities. However, most of the processes that support the chemical transformation of methane (natural gas) into these products generate a stoichiometric amount of CO_2 emissions relative to the mass of the feedstocks used in the process. For the purposes of this report, we are simply assuming

that all-natural gas stocks are combusted. BLM Colorado is assuming 100 percent combustion of coal as well, as we are unaware of any other non-combustion uses for coal stocks at non-trivial scales. **Table 2.2-19** 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.

Table 2.2-19 2017 U.S. Total and Federal Fossil Fuel Emissions

Fuel (scope)	Production (units)	% Total	% Federal	CO_2	CO_2e	% CB
U.S. Natural Gas (Total)	33,177,826,000 (Mcf)	100%	NA	1,806.20	1,808.42	0.3612%
U.S. Natural Gas (Federal)	4,327,941,937 (Mcf)	13.04%	100%	235.61	235.9	0.0471%
Colorado Natural Gas (Federal)	650,286,607 (Mcf)	1.96%	15.03%	35.40	35.45	0.0071%
U.S. Petroleum (Total)	3,418,954,000 (bbls)	100%	NA	1,403.72	1,408.99	0.2807%
U.S. Petroleum (Federal)	811,690,488 (bbls)	23.74%	100%	350.8	352.11	0.0667%
Colorado Petroleum (Federal)	5,203,706 (bbls)	0.15%	0.64%	2.25	2.26	0.0004%
U.S. Coal (Total)	774,609,357 (tons)	100%	NA	1,795.05	1,811.87	0.3590%
U.S. Coal (Federal)	326,073,802 (tons)	42.23%	100%	758.12	765.22	0.1516%
Colorado Coal (Federal)*	8,310,231 (tons)	1.08%	2.55%	19.32	19.50	0.0039%

Emissions units are Million Metric Tons, Estimates are based on EPA emissions factors, *Data assumes 50 percent federal DRMS production for Federal mines with no ONRR documentation, percent Carbon Budget (CB) calculated for mean face value (500Gt)

The snapshot data above shows that consuming all of the Federal energy produced in the U.S. in 2017 (onshore & offshore) would be equivalent to 0.26 percent of the remaining carbon budget, while the Colorado component of the Federal mineral estate is approximately 0.01 percent of the carbon budget and just 1.14 percent of total U.S. fossil fuel energy emissions (CO_2e) on an annual basis. At the current production rates shown, total Federal mineral combustion would exhaust the carbon budget in approximately 377 years, while Federal minerals in Colorado would do the same in about 8,794 years. These timelines show a stark contrast relative to the current global scope emissions track. The data also provides a nice illustration of 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 percent+ of CO_2e). Due to this fact, BLM Colorado is limiting further downstream combustion estimates to CO_2 only for the remainder of this report.

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 the with 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. Contrasting 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.

Proxy emissions are estimated by projecting all of the reasonably foreseeable direct and indirect GHGs associated with the CARMMS scenarios (low and high) forward to two specific future years (**Table 2.2-20**). The study analyzed linear rates of oil, gas, and coal exploration and development (upstream) over a ten-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 EPA 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 five 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, and thus 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 emission declines to net zero in 2050, which also assumes the entire budget is consumed.

Table 2.2-20 BLM Colorado (Federal) Projected Upstream and Downstream Emissions (MMtonnes)

Scenario	CO_2	CH_4	N_2O	CO_2e	% CB (2018 - 2032)	% CB (2018 - 2050)
Low Oil and Gas - Upstream	141	3	0	254	0.012%	0.028%
Low Oil and Gas - Downstream	1,412	NA	NA	NA	0.12%	0.28%
Low Coal - Upstream	5.81	1.52	0.00	61.28	0.005%	0.012%
Low Coal - Downstream	616	NA	NA	NA	0.06%	0.12%
Total Low	**2,171**	NA	NA	NA	**0.2%**	**0.44%**
High Oil and Gas - Upstream	261	5	0	441	0.023%	0.052%
High Oil and Gas - Downstream	2,612	NA	NA	NA	0.22%	0.53%
High Coal - Upstream	6.55	3.39	0.00	129.28	0.011%	0.026%
High Coal - Downstream	616	NA	NA	NA	0.06%	0.12%
Total High	**3,496**	NA	NA	NA	**0.31%**	**0.73%**

Percent Carbon Budget (CB) calculated for mean face value (500Gt), Table emissions are for the 2018 to 2050 projection period

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 is 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 try and apply to the national scope. In order to estimate the upstream portion of the national emissions scope, the Bureau 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. This data shows that production, processing, and transport emissions account for approximately 5 percent of the total life-cycle emissions for coal-fired power generation and 15 percent 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. For the report year, onshore Federal production accounted for 74.3 percent of all natural gas produced and 31.2 percent of all oil production (coal production is obviously 100 percent onshore). Applying the

onshore percentages to the projected emissions scenarios shows BLM's potential decision scope of approximately 3.32 percent to 7.15 percent of the carbon budget. As a nation, the total projected demand for all fossil fuels (Federal, non-Federal, domestic and imported) relative to the future year projections would result in the consumption of between 16.7 percent to 35.9 percent of the carbon budget. Federal scope emissions would account for approximately 20 percent of the national scope budget consumption for either projection scenario.

The Proposed Action is expected to extend the life of the mine for 22 years with a total of 17 million tons of coal being mined (19 years @ 800,000 tons and 3 years @ 600,000 tons). Direct, indirect, and downstream coal combustion emissions were calculated over the life of the mine (22 years). Based on estimated mining rates, EPA FLIGHT data from 2017 for the Tijeras and Pueblo cement facilities and current estimated downstream combustion, approximately 450.6 million tons of CO_2e could be emitted over the life of the project. This value represents approximately 0.09 percent of the mean face value (500 $GtCO_2$) of the carbon budget.

Projected Climate Impacts

The following information on predicted climate change has been summarized from the Intergovernmental Panel on Climate Change (IPCC).

The future climate equilibrium is dependent upon warming caused by past anthropogenic emissions, future anthropogenic emissions, and natural variability. 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 0.3°C to 0.7°C (medium confidence). The projection assumes no major volcanic eruptions, changes in natural emissions sources (e.g., CH4 and N2O), or unexpected changes in total solar irradiance. By 2050, the magnitude of the projected climate change is significantly affected by the overall emissions path the world is tracking along.

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 arid regions are expected 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. Models also predict 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 percent) for RCP2.6 and 0.14 to 0.15 (38 to 41 percent) 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 percent - RCP2.6 to 81 percent - 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 percent of the ocean area, where about 70 percent of coastlines worldwide would experience a sea level change within ±20 percent 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 percent to +6 percent for RCP 4.5 percent, and -3 percent to +8 percent under RCP8.5. Nearly all 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, most of the 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:

- 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,8 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 meters 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 NCA report.

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 greenhouse gas 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.

The following data have been summarized from the Centers for Disease Control and Prevention's Climate Effects on Health assessment.

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 ozone and/or particulate matter air pollution in some locations. Ground-level ozone (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 ozone formation include heat, concentrations of precursor chemicals, and methane emissions, whereas particulate matter 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 particulate matter, carbon monoxide, nitrogen oxides, and various VOCs (which are ozone 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 (commonly known by its acronym, 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 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.

Climate Change Mitigation

The 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 percent). Continued demand for cement is also highly likely. 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 actions 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. The data also suggests that as global emissions decline the Federal decision scope becomes more relevant to address the issue, and as such we assume that laws, regulations, and policy guidelines will evolve to provide side rails for Federal agencies to follow as an appropriate response.

2.3 Water Resources

2.3.1 Affected Environment

Water resources in the vicinity of the King II Mine include surface water resources in streams, drainages, irrigation ditches, and reservoirs, and groundwater resources in the underlying geologic formations of the Mesa Verde Group. For the purposes of this analysis, the cumulative impact area for surface water resources is designated to include the Hay Gulch area and water diverted from the La Plata River to Hay Gulch, the Mormon Reservoir located approximately five miles (8.0 km) south of the King II Mine portal, and the main stem of the La Plata River affected by National Pollutant Discharge Elimination System (NPDES) discharge permits held by the King II Mine. The groundwater cumulative impact area is designated to include the Hay Gulch alluvial groundwater within the permit area of the King II Mine and groundwater located in the Cliff House, Menefee, and Point Lookout formations within the permit area of the King II Mine. The cumulative impact analysis areas (CIAAs) for surface and groundwater follow the designation of these CIAAs in OSMRE (2017). **Figure 2.3-1** shows the location of water resource CIAAs.

2.3.1.1 Water Uses and Designations

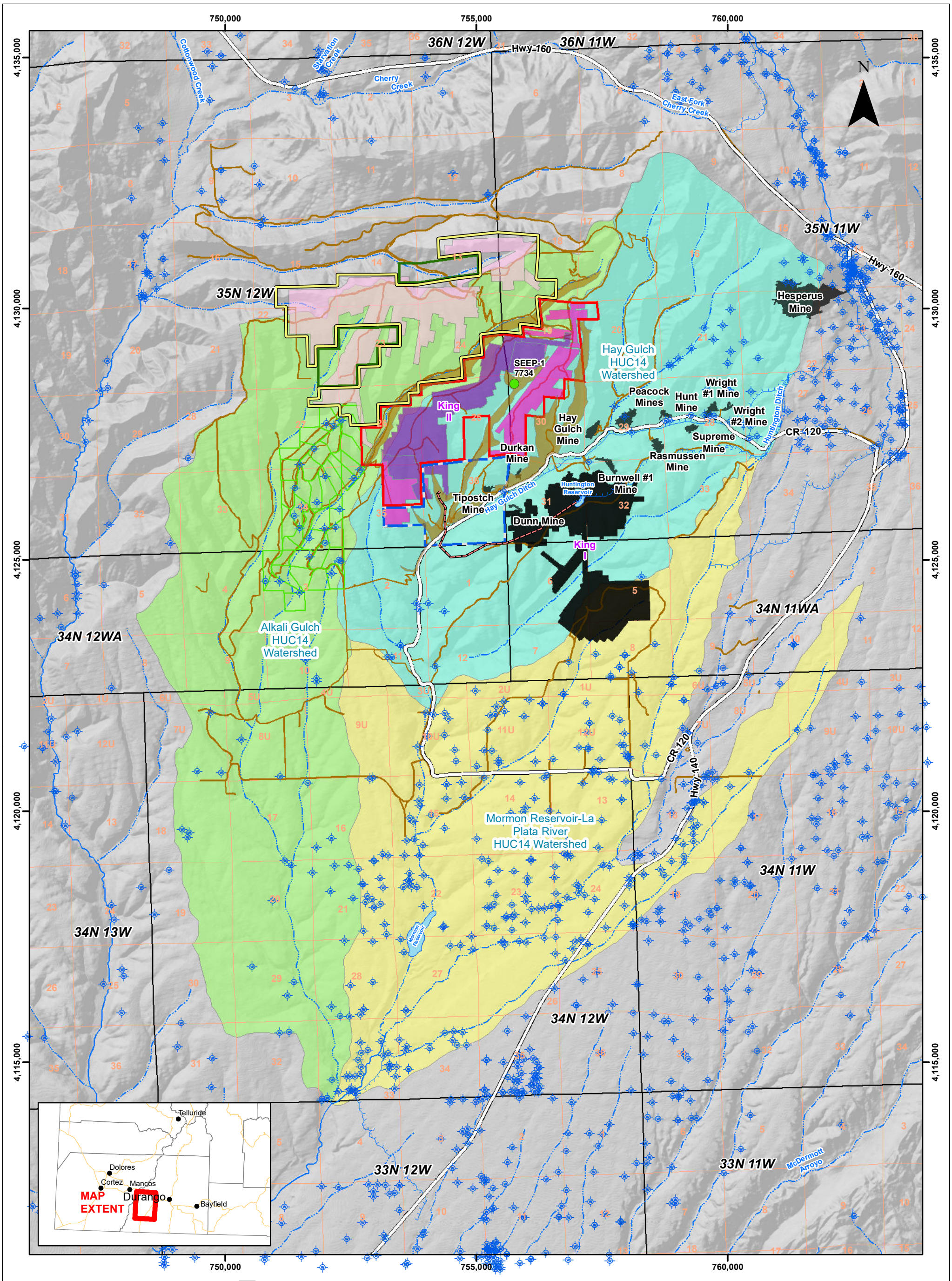
Water uses within the surface and groundwater CIAAs include domestic water supply, agricultural water supply, livestock water, and water involved in aquatic and wildlife and fish consumption (OSMRE 2017).

Domestic water supply is either water hauled into the permit area from municipal water supplies or groundwater produced from the lower Menefee or upper Point Lookout formations. Agricultural water supply comes from water imported to Hay Gulch from outside the CIAA. Livestock water is from the Hay Gulch ditch used for livestock watering. Mormon Reservoir is not permitted for recreational use. Also, there is no fishing in Mormon Reservoir, so there is no aquatic wildlife or fish consumption water in the CIAA (OSMRE 2017).

GCC has water rights as allocated by permit CO0106C. Approximately 14.07 acre-ft of water is acquired by GCC from the Huntington Ditch each year for mining dust suppression and bath house facility operational use. The water is purchased from a commercial water provided in accordance with the Colorado District Court Water Division 7 Decree 07W100 dated April 20, 2011. The water is totally consumed by the mine, bath house water being treated by a septic system on site and dust suppression water being carried as vapor by ventilation.

2.3.1.2 Baseline Hydrologic Conditions

The hydrologic study area for surface and groundwater resources encompasses Hay Gulch and areas adjacent to Hay Gulch within the surface and groundwater CIAAs, as shown on **Figure 2.3-1**. The area is traditional ranch land divided among private, State of Colorado, BLM, and Ute Mountain Ute (UMU) and Southern Ute tribal ownership. Underground coal mining is accessed via La Plata CR 120. Approximately 800,000 tons of coal is currently produced annually from 565 acres in the King II Mine. The area is located at the northwestern margin of the San Juan Basin, a structural coal-bearing basin that extends from northwestern New Mexico into Colorado, covers approximately 26,000 acres in Colorado, and contains



- CDWR-Permitted Domestic Water Well
- Seep
- Huntington Pipeline
- Main Roads
- Minor Roads
- Canal Ditch
- Intermittent Stream
- Perennial Stream
- Water Body
- Alkali Gulch HUC Watershed
- Hay Gulch HUC Watershed
- Mormon Reservoir-La Plata River HUC Watershed
- 2015-2016 Spring & Seep Survey
- Township
- Section
- Vista del Oro Subdivision
- Fee Lease Area
- Lease by Application
- Federal Permit CO-0106
- State Permit C-1981-035
- Historic Coal Mine

King II Mine Underground Workings Outline

- Existing
- Approved
- Proposed

Project Information:
Coordinate System: NAD 1983 UTM Zone 12N
Projection: Transverse Mercator
Datum: North American 1983
Units: Meter

Data Source:
GCC, NED, NHD

0 0.5 1 1.5 2
Miles

FIGURE 2.3-1

King II Mine Cumulative Impact Area

DATE: 3/22/2019	BY: MDK	CHECKED: LJB

RESOURCE HYDROGEOLOGIC SERVICES

KingMine_CumulativeImpactArea.mxd

coal-bearing sedimentary rocks of Late Cretaceous age (100-65 million years ago). Coal was deposited in a series of regressive/transgressive shoreline migrations in marginal-shore swamps, marshes, and other marine sediments deposited behind barrier beaches that formed a northwest/southeast trend. These coal-bearing sediments were transected by northeast-trending streams, resulting in the fragmentation of the coal deposits by stream sediments. The main Late Cretaceous geologic units of hydrologic interest are part of the Mesaverde Group and include the Cliff House Sandstone, the Menefee Formation (coal-bearing unit), and the Point Lookout Sandstone. These are overlain by Quaternary age sediments in stream channels, of which the Hay Gulch alluvium is the most important hydrologic unit (RHS 2016a).

2.3.1.3 Surface Water Resources

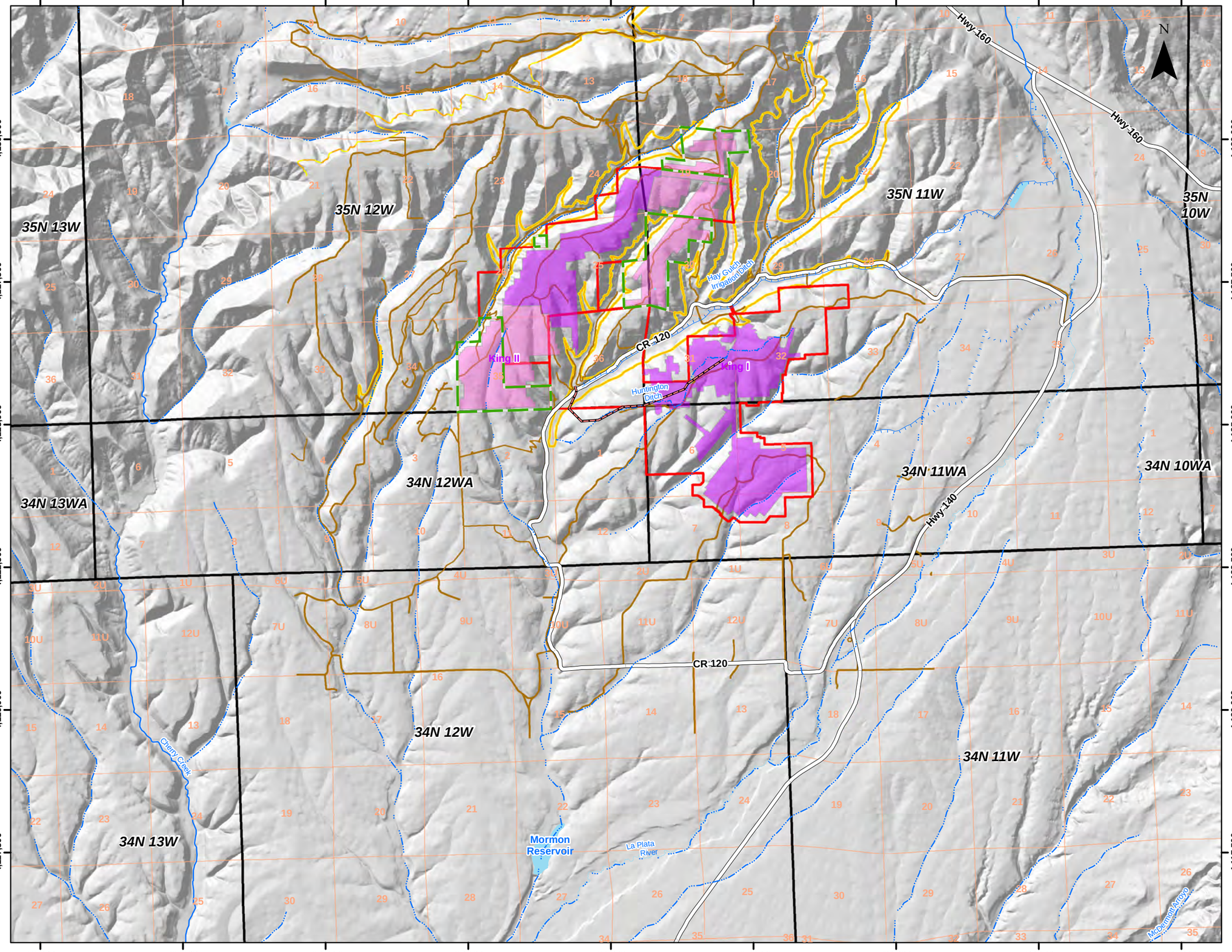
The surface water drainages within the CIAA for surface water are considered ephemeral and intermittent by OSMRE based on 30 CFR 701.5 (OSMRE 2017). There are no perennial streams in the CIAA; however, Hay Gulch Ditch and the Huntington Ditch/Reservoir/Pipeline carry irrigation water diverted from the La Plata River on a year-round basis. The Mormon Reservoir, a 26-acre reservoir constructed in 1910 for irrigation water has a capacity of 1,100-acre ft and holds water on a year-round basis. Ephemeral streams flow only in response to precipitation events or snow melt. East Alkali Gulch and West Alkali Gulch are ephemeral drainages that cross the King II workings and are tributary to Hay Gulch below the Mormon Reservoir. An intermittent stream is a stream with a portion of the stream below the water table, so that there may be flow in a segment of the stream over part of the year that is derived from groundwater. Surface water features are shown in **Figure 2.3-2**. Because there are no perennial streams and surface water resources are limited in this semi-arid environment, surface water quantity and quality are related mainly to storm water runoff and snowmelt.

Surface Water Regulatory Requirements

Surface water runoff from mining areas is required to be managed in a manner that prevents additional contribution of suspended solids to streams outside the permit area to the extent possible with best available technology (30 CFR 816.41(d)). GCCE complies with this requirement by designing, constructing, and maintaining siltation structures, impoundments, and clean water diversions. Quarterly reports are submitted to CDPHE Water Quality Control Division as required by GCC's NPDES Permit #COG85001.

Surface Water Baseline Quantity

Because of the lack of perennial streams in the CIAA, quantification of surface water is limited to storm water events or flow in irrigation ditches (OSMRE 2017). No storm water events have been successfully measured for flow or water quality to date. The Hay Gulch Ditch is monitored on a quarterly basis at two locations, the Hay Gulch Ditch Upgradient and the Hay Gulch Ditch Downgradient locations. These monitoring sites are located upgradient and downgradient respectively of the King I and King II mines. Monitoring for the period from April 2016 through March 2017 showed a range of flow from 0.28 to 1.5 cubic ft per second (cfs). Upgradient and downgradient flow rates were comparable and seldom varied by more than 20 percent. The typical flow rate at these locations was on the order of 1 cfs (OSMRE 2017). The Huntington Ditch, which delivers the King II Mine operations water supply is not specifically monitored for flow, but the Huntington Reservoir that the ditch flows into typically holds about 40 acre-ft of water.



"A" Coal Seam Outcrop
"A" Coal Seam Outcrop - Projected
Canal Ditch
Intermittent Stream
Perennial Stream
Huntington Pipeline
Main Roads
Minor Roads
Water Body
Township
Section
GCC Permit Boundary
Lease Modification 1 Boundary Area

King I & II Mine Underground Workings Outline

Existing
Proposed

Data Source:
GCC, NED, NHD (1:100,000)
Project Information:
Coordinate System: NAD 1983 UTM Zone 12N
Projection: Transverse Mercator
Datum: North American 1983
Units: Meter

0 0.5 1 1.5 2
Miles
1 inch = 1 mile

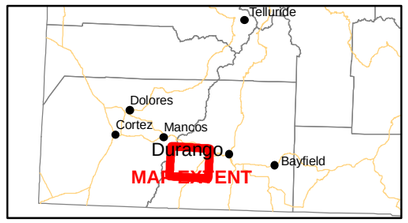


FIGURE 2.3-2

Surface Water Features

DATE: 1/31/2016	BY: MK	CHECKED: LJB

RESOURCE HYDROGEOLOGIC SERVICES

KingMine_SurfaceWater.mxd

Surface Water Baseline Quality

Surface water quality consists of water in the Hay Gulch Ditch, storm water runoff water, and water in the Mormon Reservoir. Irrigation water in the Hay Gulch Ditch is monitored as is water quality in the Mormon Reservoir. To date, there are no data on water quality in storm water runoff. The Hay Gulch Ditch derives its irrigation water from the La Plata River and the ditch water picks up some salinity from the Hay Gulch Valley floor (OSMRE 2017). The pH of Hay Gulch Ditch water is around 8.2 standard units (su) and the total dissolved solids (TDS) ranges from 180 to 320 milligrams per liter (mg/L). Stiff diagrams prepared by OSMRE (2017) indicate that the water is mainly calcium bicarbonate water. Water in the Mormon Reservoir, however, is mostly calcium/magnesium sulfate water with a pH around 7.8 su and a TDS between 1,000 and 1,500 mg/L. The elevated TDS is due to evaporative concentration and contributions from alluvial groundwater (OSMRE 2017). Complete water quality analyses can be found in RHS (2016b).

2.3.1.4 Groundwater Resources

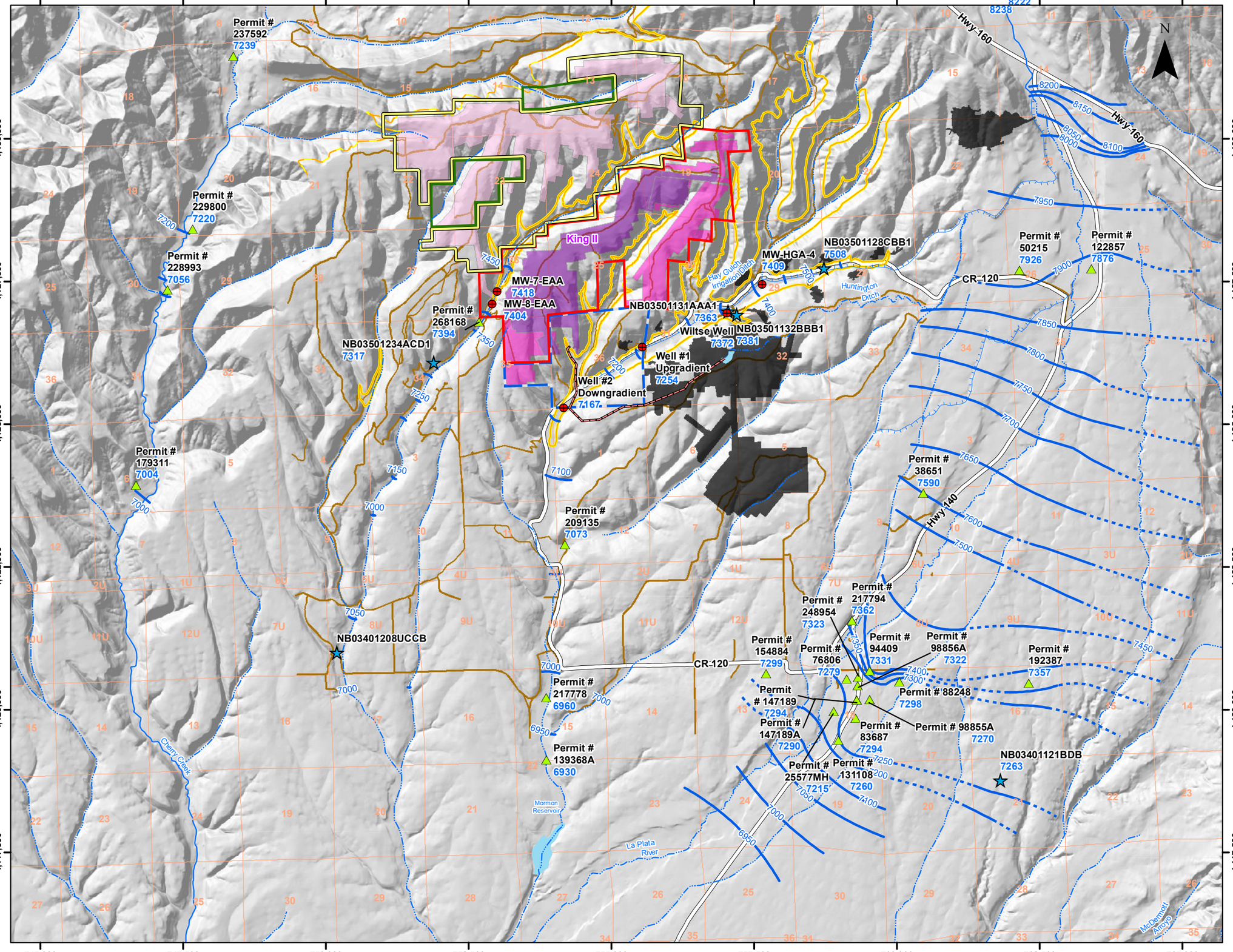
Groundwater in the Project Area and the CIAA is found in the alluvium of Hay Gulch and other drainages and in bedrock in the Cliff House Sandstone, Menefee Formation, and the Point Lookout Sandstone members of the late Cretaceous Mesaverde Group.

Groundwater Regulatory Requirements

Groundwater use by mining activities is regulated by 30 CFR 816.4(h), which states that if the water supply of an owner of interest for domestic, agricultural, industrial, or other permitted use is adversely impacted by contamination, reduction in water supply, or interruption of water supply from surface mining activities, the impacted water resource shall be replaced by the mining activity at fault. GCCE monitors groundwater quality and quantity from numerous bedrock and alluvial monitoring wells. The location of the monitoring wells is shown in **Figure 2.3-3** and the well data are presented in **Table 2.3-1**.

Alluvial Groundwater

Alluvial groundwater is present in some of the unconsolidated alluvial sediments that fill topographic lows in ephemeral stream systems. These alluvial sediments are composed of fine sand eroded from the Mesaverde formations. Alluvium in the upper reaches of drainages is typically not saturated, while alluvium in the lower reaches of drainages can be saturated in the spring and have a water level greater than 6 ft bgs during the summer months. Hay Gulch has groundwater that is sufficient in quantity for agricultural and stock watering use. Other drainages in the CIAA, such as East and West Alkali Gulch, usually have insufficient groundwater for agricultural use. The alluvial aquifers are not known to have substantial clay covers and are therefore characterized as unconfined aquifers (RHS 2016a).



MW-HGA-4 Well Name
7409 Groundwater Elevation (ft AMSL)

- GCC Compliance Alluvial Monitoring Well
- Alluvial Well
- Alluvial Well – 1983 USGS Level Survey
- "A" Coal Seam Outcrop
- "A" Coal Seam Outcrop - Projected
- Canal Ditch
- Intermittent Stream
- Perennial Stream
- Alluvial GW Contour - 50' Interval
- Alluvial GW Contour (Projected)
- Huntington Pipeline
- Main Roads
- Minor Roads
- Water Body
- Section
- Fee Lease Area
- Lease by Application
- Federal Permit CO-0106
- State Permit C-1981-035
- Historic Coal Mine

King II Mine Underground Workings Outline

- Existing
- Approved
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Data Source:
GCC, NED, NHD
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Coordinate System: NAD 1983 UTM Zone 12N
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Units: Meter

0 0.5 1 1.5 2
Miles
1 inch = 1 mile

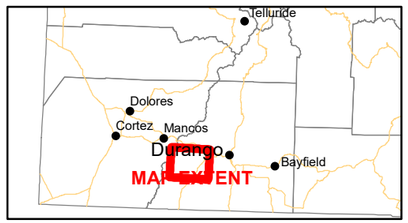

FIGURE 2.3-3

Alluvial Groundwater Monitoring Well and Contour Map

DATE: 3/22/2019	BY: MDK	CHECKED: LJB

RESOURCE HYDROGEOLOGIC SERVICES

KingMine_Potentiometric_2019.mxd

Table 2.3-1 GCCE Compliance Monitoring Well Construction Data

Location ID	Alternate ID	Year Installed	Total Depth (ftbgs)	Well Diameter (inches)	Well Casing Material	Screened Interval (ftbgs)	Screened/ Open Interval Name
Wiltse Well	Wiltse	1977+/-	12.7	48	Galvanized corrugated steel	0-12.7	Hay Gulch Alluvium
Well #1 Upgradient	Ute Mountain Ute Tribe	1998+/-	66.7	6-5/8	Carbon steel	No record	Hay Gulch Alluvium
Well #2 Upgradient	King II	2004	17.25	2	PVC	7.2-17.2	Hay Gulch Alluvium
MW-HGA-4	Wiltse Upgradient	2016	43	2	PVC	8.2-43.2	Hay Gulch Alluvium
MW-1-MI	NA	2017	261.4	2	PVC	241.1-261.1	Menefee Interburden
MW-1-A	NA	2017	232.3	2	PVC	222.0-232.0	“A” Seam Coal
MW-1-C	NA	2017	219.5	2	PVC	46.7-219.2	Cliff House Formation
MW-2-MI	NA	2017	318.4	2	PVC	298.1-318.1	Menefee Interburden
MW-2-A	NA	2017	291.0	2	PVC	280.7-290.7	“A” Seam Coal
MW-2-C	NA	2017	273.9	7	Open hole below carbon steel surface casing	41.4-273.6	Cliff House Formation
MW-3-MI	NA	2017	375.0	2	PVC	359.7-374.7	Menefee Interburden
MW-3-A	NA	2017	355.0	2	PVC	352.2-354.7	“A” Seam Coal
MW-3-C	NA	2017	344.9	2	PVC	44.6-344.6	Cliff House Formation
MW-4-MI	NA	2017	389.4	2	PVC	369.1-389.1	Menefee Interburden
MW-4-A	NA	2017	366.7	2	PVC	349.0-366.5	“A” Seam Coal
MW-4-C	NA	2017	341.0	2	PVC	43.2-340.7	Cliff House Formation
MW-5-MI	NA	2017	282.8	2	PVC	262.5-282.5	Menefee Interburden
MW-5-A	NA	2017	254.3	2	PVC	249.0-254.0	“A” Seam Coal

Location ID	Alternate ID	Year Installed	Total Depth (ftbgs)	Well Diameter (inches)	Well Casing Material	Screened Interval (ftbgs)	Screened/ Open Interval Name
MW-5-C	NA	2017	249.6	7	Open hole below carbon steel surface casing	39.0-249.3	Cliff House Formation
MW-6-LM	NA	2018	585.25	2	PVC	535-585	Lower Menefee
MW-6-MI	NA	2018	376.25	2	PVC	341-376	Menefee Interburden
MW-6-A	NA	2018	325.45	2	PVC	315-325	"A" Seam Coal
MW-6-C	NA	2018	297.10	2	PVC	47-297	Cliff House Formation
MW-7-EAA	NA	2018	66.95	2	PVC	17-67	East Alkali Gulch Alluvium
MW-8-PL	NA	2018	310.45	2	PVC	290-310	Point Lookout Formation
MW-8-LM	NA	2018	250.25	2	PVC	210-250	Lower Menefee
MW-8-MI	NA	2018	100.38	2	PVC	90-100	Menefee Interburden
MW-8-EAA	NA	2018	68.74	2	PVC	18-68	East Alkali Gulch Alluvium

Ftbgs – ft below ground surface

Alluvial Groundwater Baseline Quantity

The presence and character of alluvial groundwater in the regional area is documented in publicly available reports for domestic, agricultural, or commercial well construction. An inventory of these well reports is summarized by RHS (2016a) and the location of the wells is shown in **Figure 2.3-3**, an alluvial groundwater contour map compiled from data sources that include CDWR well construction and test reports, the USGS 1985 report in the Hydrology of Coal-Lease Areas near Durango, Colorado (Brooks 1985), and GCCE Energy well construction reports.

The La Plata River alluvial aquifer along the eastern margin of the CIAA contains very productive wells with hundreds of permitted domestic wells that yield up to 65 gallons per minute (gpm) (RHS 2016a). Alluvial water levels in the La Plata River east of Hay Gulch are on the order of 300 ft higher than those measured in Hay Gulch (OSMRE 2017). Domestic wells in the Cherry Creek alluvium along the western boundary of the regional study area have yields up to 30 gpm. In contrast, alluvium in the East and West Alkali Gulch

areas have not been developed for water due to: 1) low population density and thus low demand; 2) water quality elevated in sulfate and TDS; and 3) low yield.

Along the western margin of the King II Mine underground workings, the East Alkali Gulch alluvium appears to have spatially limited groundwater saturation (RHS 2016a). Water well CDWR #268168 has been completed to a depth of 100 ft in gravel, while well CDWR #268278 located 675 ft downgradient was dry through the alluvium and was completed in the underlying Menefee Formation (OSMRE 2017).

Alluvial groundwater monitoring is conducted quarterly by GCCE at four groundwater monitoring wells in Hay Gulch. Two additional alluvial monitoring wells were installed in 2018 to monitor conditions upgradient and downgradient of the proposed LCC. These wells are shown on **Figure 2.3-3** and are completed at a depth ranging from 14 to 67 ft bgs. GCCE monitoring demonstrates long-term water level stability with typical seasonal water level fluctuations in the unconfined alluvial gravels and sands of Hay Gulch (OSMRE 2017). Borehole alluvial cuttings in monitoring well MW-HGA-4 indicate that the alluvium of Hay Gulch is dominated by fine to very fine sands, saturated clay loam, and sandy clay intervals along with saturated gravel intervals from 38 to 42 ft bgs. The alluvium at well location MW-HGA-4 is greater than 80 ft thick.

Alluvial Groundwater Baseline Quality

Alluvial groundwater quality has been monitored for several years by GCCE and found to vary both spatially and temporally (OSMRE 2017). **Figure 2.3-4** displays the water quality in the four monitoring wells sampled on a regular basis. The Wiltse Well is dominated by calcium/magnesium sulfate, while well MW-HGA-4 is dominated by calcium/magnesium bicarbonate. Well #1 upgradient is dominated by sodium/magnesium bicarbonate, while Well #2 downgradient is dominated by calcium/magnesium bicarbonate. Well #1 upgradient is in Hay Gulch below the King I Mine portal, while Well #2 downgradient is below the King II Mine portal and shows water quality similar to Hay Gulch ditch water. Well MW-HGA-4 is at the confluence with Roberts Gulch and has similar water quality to the Wiltse Well. The pH in these four monitoring wells ranges from 7.2 to 7.7 su, while TDS ranges from 495 to 760 mg/L in all wells but the Wiltse Well. The Wiltse Well has a TDS in the range of 1,480 to 1,580 mg/L. The Wiltse Well and Well MW-HGA-4 have sulfate between 400 and 800 mg/L (OSMRE 2017). Complete water quality analyses can be found in RHS (2016b).

Groundwater quality in Alkali Gulch is monitored by two wells, MW-7EAA (upgradient) and MW-8EAA (downgradient). Water quality data obtained over two quarters in 2018 and 2019 (P. Clark, pers. comm) show that the depth to water increases slightly from 36 to 40 ft bgs downgradient in Alkali Gulch and TDS decreases from around 1,460 to 1,480 mg/L to 1,220 to 1,290 mg/L. Sulfate also decreases from around 732 mg/L to 533 to 559 mg/L as bicarbonate increases from the 360 to 380 mg/L range to 400 to 435 mg/L. The water quality in both monitoring wells is calcium/magnesium sulfate water and the water does not meet drinking water standards.

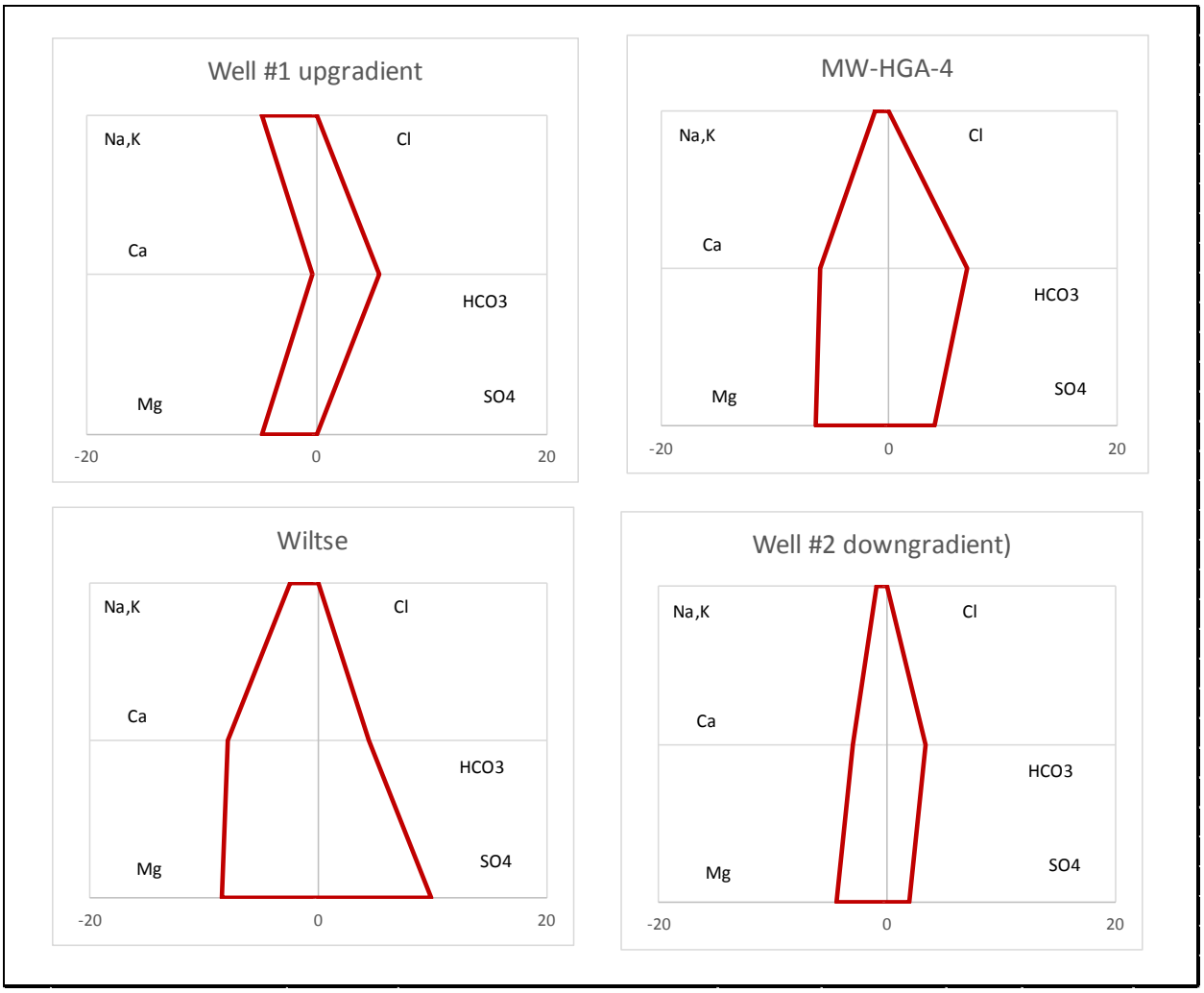

Figure 2.3-4: Alluvial Groundwater Quality: Major ions in Hay Gulch alluvial groundwater upgradient (upper two plots), near the King I portal, and downgradient of the King II portal, 2016 samples

Cliff House Sandstone Groundwater

The Cliff House Sandstone is the uppermost bedrock unit in the King II Mine area and within the CIAA and therefore dominates surface exposures of bedrock. The thickness averages 350 ft and the formation is dissected by drainages originating from mesa tops (OSMRE 2017). The Cliff House Sandstone is marine in origin and consists of lenticular ledges of hard, fine to medium-grained calcareous sandstone in a matrix of softer, clayey sandstones, silty shales, and mudstones. The formation thins to the east.

Cliff House Baseline Groundwater Quantity

The Cliff House Sandstone is known regionally in the San Juan Basin to be an aquifer with wells yielding up to 17 gpm and averaging around 10 gpm in yield. The estimated transmissivity is around 2.0 ft squared/day (Brooks 1985). However, in the CIAA the Cliff House Sandstone is dissected by deeply incised drainages trending northeast/southwest that follow the paleotopography of the Cliff House. This erosional pattern has effectively isolated the Cliff House into elongate, lobed geometric bodies that do not contain an aquifer due to the lack of interconnection between the sandstone bodies. These topographic features, referred to locally as mesas, range from 0.5 to 1.0 miles (800 to 1,600 meters) in width and can be several miles long. In the northern part of the CIAA, generally north of Hay Gulch and in the vicinity of the King II Mine, these Cliff House mesas are isolated on all sides with outcrop exposures. In the southern part of the CIAA near the King I Mine, the Cliff House mesas are approximately 1.5 miles (2.4 km) wide. Some perched water-bearing intervals have been identified by GCCE during mining due to minor leakage from the mine roof, with drainage on the order of several gpm lasting several minutes (OSMRE 2017).

In 2017 and 2018, GCCE installed a cluster of bedrock monitoring wells at six locations within the CIAA. Each location includes a monitoring well screened within the Cliff House Sandstone. Drilling of the monitoring well clusters demonstrated that the Cliff House is basically unsaturated but does contain minor water-bearing fractures. **Table 2.3-2** summarizes the water level data in the cluster of monitoring wells. Most wells screened in the Cliff House were dry or contained water after drilling but soon dried out (OSMRE 2017).

Cliff House Baseline Groundwater Quality

Monitor wells screened in the Cliff House Sandstone have water only in short water columns (less than 10 ft of standing water) at the bottom of the wells, which are generally greater than 200 ft bgs. This is because the Cliff House is generally unsaturated (OSMRE 2017). **Figure 2.3-5** presents Stiff diagrams for water quality in the Cliff House monitor wells. Monitor well MW-1C has sodium sulfate water, while MW-3C and MW-4C have sodium bicarbonate water. Seep-1, which originates from the base of the formation at approximately 1 gpm (OSMRE 2017), is mainly magnesium sulfate water. The pH is MW-1C and MW-3C is around 8.4 to 8.6 su, while the pH in MW-4C and Seep-1 is 7.6 su. TDS in MW-1C is 2,285 mg/L, while that in MW-3C is 1,910 mg/L. MW-4C and Seep-1 have TDS values of 3,432 mg/L and 3,480 mg/L, respectively. This limited sampling of available groundwater in the Cliff House Sandstone suggests that groundwater is not laterally continuous in the formation (OSMRE 2017). Complete water quality analyses can be found in RHS (2016b).

Table 2.3-2 GCCE Bedrock Cluster Monitoring Well Water Levels, February 2019

Location Name	Measurement Date	Well Total Depth (ftbgs)	Depth to Water (ftbgs)	Water Column Length (ft)	Well Ground Surface Elevation (ftamsl)	Groundwater Potentiometric Elevation (ftasml)
MW-1-C	6/7/2017	219.50	216.50	3.00	8519.78	8303.28
MW-1-A	6/7/2017	232.30	215.42	16.88	8520.37	8304.95
MW-1-MI	6/7/2017	261.40	259.99	1.41	8520.84	8260.85
MW-2-C	6/7/2017	273.90	Dry	Dry	7711.73	Dry
MW-2-A	6/7/2017	291.00	Dry	Dry	7712.96	Dry
MW-2-MI	6/7/2017	318.42	Dry	Dry	7713.52	Dry
MW-3-C	6/30/2017	344.85	296.30	48.55	7416.64	7120.34
MW-3-A	6/30/2017	355.00	298.24	56.76	7416.58	7118.34
MW-3-MI	6/30/2017	375.00	241.15	133.85	7416.29	7175.14
MW-4-C	6/30/2017	341.00	314.05	26.95	7568.80	7254.75
MW-4-A	6/30/2017	366.74	334.96	31.78	7569.47	7234.51
MW-4-MI	6/16/2017	389.35	330.15	59.20	7569.73	7239.58
MW-5-C	6/7/2017	249.55	248.15	1.40	8407.12	8158.97
MW-5-A	6/7/2017	254.28	Dry	Dry	8407.39	Dry
MW-5-MI	6/7/2017	282.75	276.48	6.27	8407.67	8131.19
MW-6-LM	2/25/2019	585.25	539.34	45.91	*7884	*7345
MW-6-MI	2/25/2019	376.25	367.92	8.33	*7884	*7516
MW-6-A	2/21/2019	325.45	307.40	18.05	*7884	*7577
MW-6-C	2/21/2019	297.10	Dry	Dry	*7884	Dry
MW-8-PL	2/19/2019	310.45	126.40	184.05	*7447	*7321
MW-8-LM	2/19/2019	250.25	134.30	115.95	*7447	*7313
MW-8-MI	2/19/2019	100.38	43.50	56.88	*7447	*7404

ftbgs – ft below ground surface; ftamsl – ft above mean sea level

*As-built location surveys for wells installed in December 2018 will not be completed until access is available following spring 2019 snowmelt; approximate well elevations given here are based on DEM data.

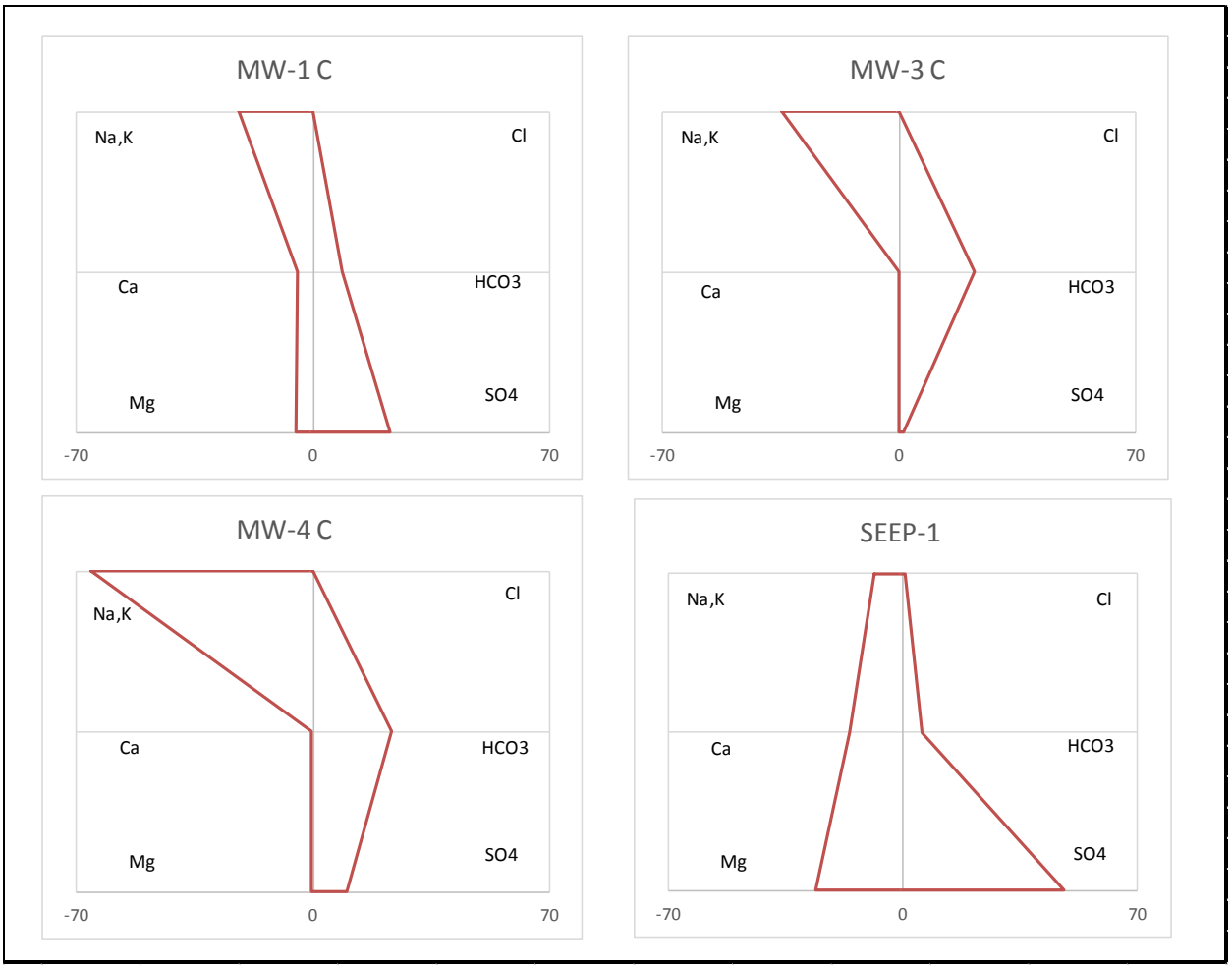

Figure 2.3-5: Cliff House Formation Water Quality: Stiff diagrams of three new wells completed in Cliff House Formation, and a seep (SEEP-1)

Menefee Formation Groundwater

The Menefee Formation is a non-marine assemblage of sandstones, shales, siltstones, and coals. This formation thins eastward and westward towards the margins of the Project Area. Bedding is irregular and rapid transitions in lithology are common. The approximate thickness within the Project Area is 300 ft (OSMRE 2017). The coal seams mined at the King I and King II mines are within the Menefee Formation. Seven coal seams have been documented by the U.S. Geological Survey (OSMRE 2017); however, the "A" and "B" seams are the most substantial in thickness and quality of coal (RHS 2016a) and the "A" seam is mined at the King II Mine in the upper Menefee Formation.

Menefee Formation Baseline Groundwater Quantity

Regionally, the lower Menefee is known to be an aquifer with well yields up to 15 gpm and an estimated transmissivity of 50 ft squared/day or less in the San Juan Basin (Brooks 1985). It is possible that the lower Menefee in the CIAA and adjacent watersheds serves as an aquifer. However, domestic well completion methods make it difficult to ascertain whether water is coming from the lower Menefee or the upper Point Lookout Sandstone (OSMRE 2017).

The upper Menefee is not known locally or regionally to be an aquifer (RHS 2016a). This interval in the Project Area is known locally to be unsaturated, based on exploration drilling by GCCE (OSMRE 2017). The lower Menefee may be an aquifer in the southern part of the CIAA as the formation deepens to the south with a regional dip of two to three degrees (OSMRE 2017).

In the northern part of the CIAA, the Menefee outcrops, exposing the "A" coal seam. To the far north in the CIAA, substantial outcrops of the Menefee Formation serve as the groundwater recharge areas for the formation (OSMRE 2017). The Menefee has been incised with surface drainages in a manner similar to the Cliff House Sandstone, but to a lesser degree because is lies stratigraphically below the Cliff House and thus has less surface exposure. Groundwater flow in the Menefee is assumed to follow the regional dip of the formation and thus flow to the south/southwest (OSMRE 2017). The incision of the Menefee by surface drainages limits groundwater interconnection within the Menefee. In the vicinity of the King II Mine, the "A" seam is exposed on the mesas created by the incision of the Menefee and thus serves as a discharge zone for water that enters the Menefee through precipitation recharge (OSMRE 2017). No springs or seeps are known in the Menefee near the King II Mine, suggesting that groundwater flow is not present in the upper Menefee in the mine area (OSMRE 2017).

In the area south of the King II Mine, the upper Menefee outcrops along the south side of Hay Gulch. The "A" coal seam is located above the Hay Gulch alluvium, suggesting that the recharge potential for groundwater in the upper Menefee is limited to the west where the "A" seam outcrop dives bgs (OSMRE 2017). Extensive drilling by GCCE south of Hay Gulch for the King I Mine exploration of the "A" and "B" coal seams to depths of 80 ft bgs encountered no groundwater (OSMRE 2017). Also, wells screened in the upper Menefee as part of the cluster of wells drilled by GCCE in 2017 and 2018 demonstrate that while there are some minor water-bearing intervals, the upper Menefee represents an inconsistent saturated/unsaturated groundwater flow regime. This is consistent with the King II Mine roof presenting only occasional perched intervals of groundwater that drain quickly during mining (OSMRE 2017).

Menefee Formation Groundwater Quality

The Menefee Formation is monitored in two separate intervals in the proposed mine extension area for the King II Mine, the upper "A" coal seam, and the sandstone-siltstone underburden or floor. Stiff diagrams for the "A" coal seam are shown in **Figure 2.3-6** and the underburden water quality is shown in **Figure 2.3-7**. Water quality in both the "A" coal seam horizon and the underburden is dominated by sodium bicarbonate. The pH values range from 7.8 to 8.8 su in both the "A" coal seam horizon and TDS ranges from 1,079 mg/L to 1,884 mg/L. Sulfate is variable, but generally less than bicarbonate. RHS (2016b) provides complete water quality analyses of the Menefee Formation groundwater.

Point Lookout Sandstone Groundwater

The Point Lookout Formation is the lowest member of interest in the Project Area. The Point Lookout consists of near-shore marine sands grading up into barrier sands. The formation is dominated by fine sands and silty sands. Water yield is low (OSMRE 2017).

Point Lookout Groundwater Quantity

The Point Lookout Formation is the lowermost formation of the Mesaverde Group and is divided into an upper massive sandstone member and a lower member consisting of sandstone interbedded with shale (RHS 2016b). Total thickness of the Point Lookout Formation is around 400 ft, with the upper member being about 100 ft thick. The Point Lookout is known to be fairly productive where extensively fractured in the upper sandstone unit (OSMRE 2017). The basal Point Lookout has low porosity and permeability and is not considered an aquifer (Johnson 1981). Transmissivity has been estimated at 240 ft squared/day in the New Mexico portion of the San Juan Basin (Brooks 1985).

The Point Lookout outcrops only north and east within the CIAA. Areas of outcrop are recharge areas for the formation. Flow is to the south following the two- to three-degree dip in the formation (OSMRE 2017). It is likely that many of the deep bedrock wells in the Project Area are drawing water from the upper sandstone in the Point Lookout Formation. It is also possible that wells screened in the lower Menefee Formation draw water from the upper Point Lookout because of possible hydraulic connection between the upper Point Lookout and the lower Menefee (OSMRE 2017).

Point Lookout Groundwater Quality

There are no wells exclusively completed in the Point Lookout in the Project Area or the CIAA, so water quality data are not available.

2.3.2 Environmental Effects

The Proposed Action would consist of the expansion of the King II Mine and the East Alkali Gulch LCC, as explained in detail in the EA. The East Alkali Gulch LLC would be in bedrock below about 25 to50 ft of alluvial material in East Alkali Gulch and would be an extension of existing underground workings needed to access coal reserves on the north side of East Alkali Gulch.

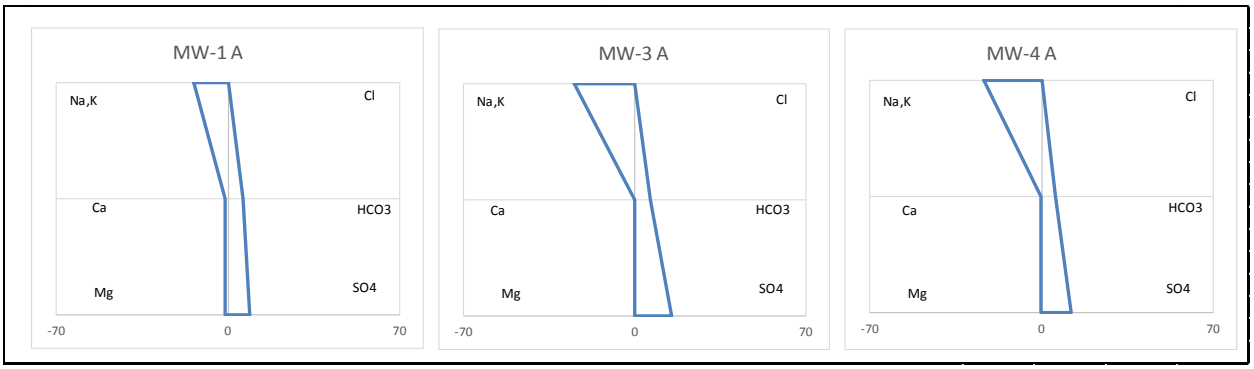

Figure 2.3-6: Menefee Formation Water Quality 'A' Seam: Stiff diagrams of the three wet wells completed in the "A" coal seam of the Menefee Formation

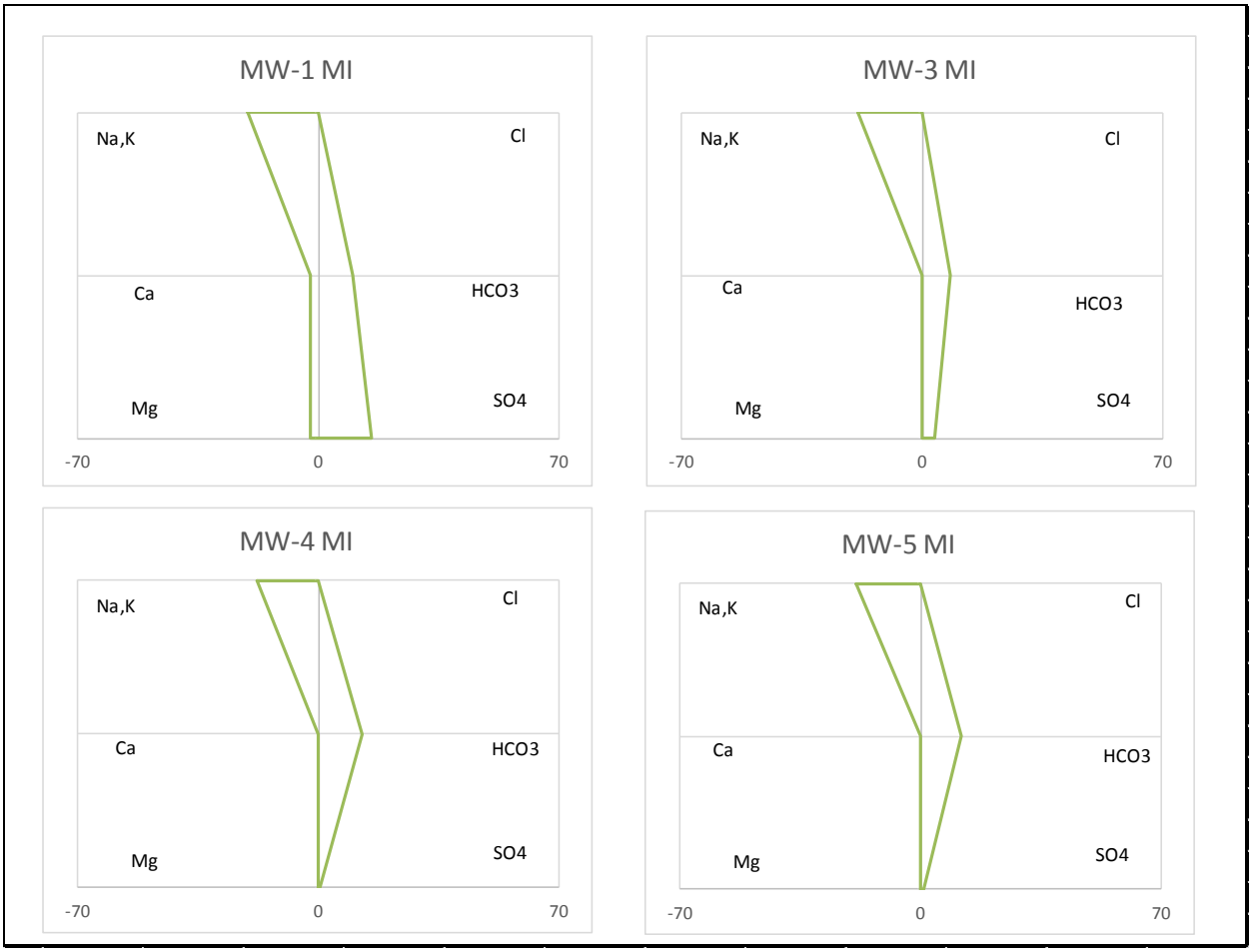

Figure 2.3-7: Menefee Formation Water Quality Below the 'A' Seam: Stiff diagrams of wells completed in the Menefee Formation immediately below the "A" seam

2.3.2.1 Direct and Indirect Effects

Surface Water

Surface water flows in the area potentially impacted by mine expansion and the LCC are limited to flow in two ditches, Hay Gulch Ditch and Huntington Ditch, that import water from outside the Hay Gulch watershed for irrigation via spreader dikes, return flows and occasional storm runoff control (OSMRE 2017). East Alkali Gulch is ephemeral and flows only during periods of heavy rainfall or during snowmelt. Monitoring by GCCE has focused on sampling ditch water above and below the existing mine operations on a quarterly basis, measurement of field parameters, and lab analysis for major ions and trace metals. No storm runoff events have been captured to date. East Alkali Gulch near the proposed crossing in bedrock would have both alluvial and bedrock groundwater monitoring wells.

Some of the ditch water is routed to the King II Mine for operational use in dust control. All of the water taken by the mine is consumed, so that there is no discharge of water taken from the ditches. Storm water facilities constructed by the mine capture the 25-year storm event.

Surface Water Quantity

The surface water balance consists of irrigation ditch imports, consumptive use of the water for mining (dust control) and irrigation, and irrigation return flows that are routed to the Mormon Reservoir. Other irrigation uses and return flows also affect Mormon Reservoir. There is minimal potential for mining to alter surface water flows. The mine's demand for water imported by ditches may vary depending on groundwater seepage into the mine and the use of this seepage water for dust control in place of ditch water. The amount of mine seepage from the mined "A" seam is minimal and thus use of mine seepage water should not significantly decrease the use of imported ditch water. The East Alkali Gulch crossing would be in bedrock and thus would not affect surface water in East Alkali Gulch. The stream crossing of East Alkali Gulch would require a temporary stream-bed crossing and thus potentially affect flow in East Alkali Gulch.

No significant change in the proposed mining rate is expected, suggesting that ditch water consumption by GCCE should remain relatively constant. Any decrease in the use of ditch water by GCCE would be temporary and have minimal effect on ditch water flows. Consequently, no impact on surface water quantity is expected from the proposed expansion of the King II Mine. Impacts to surface water flow in East Alkali Gulch due to the stream-bed crossing is possible during periods of heavy rainfall that may produce temporary flow in East Alkali Gulch.

Surface Water Quality

At present, water imported by the Hay Gulch and Huntington ditches is consumed by irrigation or mine use for dust control or collected as irrigation return flow. Irrigation return flow gains some salinity through contact with irrigated fields. The mine discharges no water and thus has no impact on surface water quality. Under the Proposed Action, the King II Mine expansion would continue to consume all imported water and not discharge water, and thus should not have an impact on surface water quality.

Ditch water imported from the La Plata River is seasonally variable in water quality, but always meets drinking water, stock water, and irrigation standards (OSMRE 2017). Below the King II Mine, there is some gain in dissolved solids from irrigation return flows, but applicable water quality standards are still met.

Storm water runoff from mine surface facilities is contained in constructed storm water impoundments. Water collected in these impoundments is sampled by GCCE and the analyses forwarded to CDPHE Water Quality Control Division prior to obtaining permission to discharge the water to Hay Gulch via the release ditch. Mine inflow water is captured by drains and sumps and consumed for dust control. Mine inflow water is similar in water quality to bedrock groundwater and would meet livestock and wildlife standards and have a high sodium adsorption ratio but would be of insufficient quantity to be used for livestock or wildlife uses.

Storm water flow in East Alkali Gulch would be temporary and water quality would be determined by runoff from the drainage area of East Alkali Gulch. Construction of roads and drill pads in the drainage area of East Alkali Gulch as part of the LCC may result in increased sediment flow to the gulch and thus impact water quality temporarily during storm runoff.

Current mine activities and the proposed expansion of the King II Mine would not be expected to impact surface water quality. Storm water runoff is captured and not released until it meets NPDES standards. Mine inflow water is consumed for dust control and not discharged. Thus, current mining activities and proposed mining under the expansion of the King II Mine would not be expected to impact surface water quality.

Groundwater

The “A” coal seam, which is the target of mining at the King II Mine, is near the top of the Menefee Formation and is composed mainly of sandstone, siltstone, shale, and coal. The Menefee Formation lies between the Cliff House Sandstone, which is above the Menefee, and the Point Lookout Formation below the Menefee. Only the upper part of the Point Lookout Formation qualifies as a significant aquifer (OSMRE 2017), although water adequate for domestic and stock water use can be obtained from the lower Menefee. Many wells completed across the coal seams have traces of CH_4 and hydrogen sulfide. Many domestic wells in the vicinity of the mines have been abandoned because of CH_4 and sulfide corrosion of iron in the wells (OSMRE 2017).

Alluvial groundwater in Hay Gulch and its tributaries has variable sulfate and relatively high TDS and is thus not favored for domestic water use (OSMRE 2017). Although GCCE has used water from the Wiltse Well near the King I Mine portal in the past, water supply for the mine is now dependent on importing water from the La Plata River via the Huntington Ditch. Groundwater is thus not a source of water supply for the King II Mine. Alluvial groundwater in East Alkali Gulch would be monitored during and after the construction of the LCC.

Alluvial Groundwater

Alluvial Groundwater Quantity

Saturated alluvium is present in Hay Gulch. Hay Gulch groundwater levels coincide with the ground surface during snowmelt periods and during the irrigation season and measure several ft bgs during the remainder of the year. Groundwater levels are measured and reported to OSMRE and Colorado Division of Reclamation Mining and Safety (CDRMS) by GCCE. Current mining by GCCE and the proposed expansion of the King II Mine would obtain operational water supply from the La Plata River via the Huntington Ditch. No alluvial groundwater would be used by the King II Mine. Thus, impacts to alluvial groundwater levels and flow are not anticipated. Similarly, the East Alkali Gulch crossing would not use alluvial groundwater. The mine extension in bedrock under East Alkali Gulch is not anticipated to impact alluvial groundwater and the stream-bed crossing would be constructed during periods of low or no flow in East Alkali Gulch and also is not anticipated to affect alluvial groundwater in East Alkali Gulch.

Alluvial Groundwater Quality

Mining operations have no potential to directly impact alluvial groundwater quality, but during the course of mining, small roof inflows could lead to diversions of some quantity of ditch water from mine use to the Gulch flow, and possibly to alluvium (OSMRE 2017). Similarly, the East Alkali Gulch crossing should not impact alluvial groundwater quality because trenching is expected to stay above the groundwater table. The alluvial groundwater would continue to be monitored by GCCE during the proposed mine expansion and during reclamation.

Cliff House Sandstone Groundwater

The Cliff House Sandstone is restricted to ridge outcrops in the Project Area and has limited water storage. Water in the Cliff House is not used for mining and one small seep discovered in 2015 is relatively isolated, used only by wildlife, and not present during drought conditions (OSMRE 2017).

Cliff House Groundwater Quantity

The Cliff House Sandstone is not an aquifer in the Project Area due to its limited extent and low permeability. Five monitoring wells completed in this unit by GCCE in 2017 had very limited water. Only three of the wells actually yielded enough water for sampling. Water in the Cliff House appears to be localized in perched areas or along fractures. The Cliff House Sandstone roof rock in the King II Mine has seeped very little water over the past 10 years of mining (OSMRE 2017). The Cliff House would continue to be monitored by GCCE during the proposed mine expansion and during reclamation. Impacts to water quantity in the Cliff House by mining have not occurred over the past 10 years and are not expected under the Proposed Action. Extension of the mine northward with the East Alkali Gulch crossing would not affect the Cliff House Sandstone. Thus, impacts to groundwater quantity are expected to be negligible.

Cliff House Sandstone Groundwater Quality

There is insufficient groundwater in the Cliff House Sandstone to sustain demonstrable impacts to groundwater quality. One seep in the Cliff House Sandstone (Seep-1) has elevated sodium and sulfate. Continued monitoring by GCCE would show whether water quality changes in Seep-1 or the three monitor wells that slowly accumulate water over time. Impacts to water quality in the Cliff House Sandstone due

to the proposed mine expansion in the King II Mine are not expected due to the limited extent of perched water in the Cliff House Sandstone and the low permeability of the formation. The East Alkali Gulch crossing would not affect the Cliff House Sandstone. Thus, impacts to groundwater quality in the Cliff House Sandstone are expected to be negligible.

Menefee Formation Groundwater

The Menefee Formation contains the coal mined by GCCE in the Project Area. The "A" coal seam, which is the target coal bed in the King II Mine, is located in the upper Menefee Formation and has been dry where mined by GCCE to date. New monitoring wells installed by GCCE have shown that the Menefee Formation contains perched water in some locations. Regionally, the lower Menefee Formation is an aquifer sourced by some domestic wells, although it contains coal-bed CH_4 and is susceptible to producing sulfide (OSMRE 2017). Some wells in the Menefee are completed across the upper Point Lookout Formation (RHS 2016a), and this leads to water in the well that is from the Point Lookout, not from the Menefee.

Menefee Formation Groundwater Quantity

Mining of the "A" coal seam of the Menefee Formation in the King II Mine for the past 10 years has not encountered saturated coals (OSMRE 2017). Exploration drilling in the CIAA by GCCE has encountered only dry conditions in the upper Menefee Formation. Monitor wells installed by GCCE in 2017 did encounter local wet conditions. However, given the discontinuous nature of sands in the Menefee and the documented dry conditions of the "A" coal seam in the King II Mine workings, it is not likely there is groundwater continuity between the wet Menefee Formation cluster monitoring wells upgradient (MW-1 and MW-5) and those downgradient (MW-4 and MW-3) in the King II Mine area (OSMRE 2017).

Mining at the King II Mine currently does not intersect groundwater in the Menefee Formation and the proposed expansion of mining is not expected to encounter groundwater. Current use of Menefee groundwater is understood to be by domestic wells that are screened across the upper Point Lookout Formation, and thus probably derive their water from the Point Lookout. Thus, it is not likely that operations in the King II Mine under the Proposed Action would adversely impact existing or potential users of the Menefee Formation water in the CIAA. This also applies to the East Alkali Gulch crossing.

Menefee Formation Groundwater Quality

GCCE monitors 10 wells completed in the Menefee Formation for water quality. Five of the wells are screened in the "A" coal seam and the other five are screened in the underburden, referred to as the Menefee Interburden. The wells are sampled quarterly. Water quality in wells that produce sufficient water for sampling appears to be within drinking water standards (OSMRE 2017), although the yield is very low and some samples have shown elevated sodium. Mining would not impact water quality in the Menefee. Any inflow to the mine workings is consumed or exhausted as vapor in the ventilation system of the mine (OSMRE 2017). The King II Mine does not discharge water into the Menefee Formation. Thus, impacts to water quality in the Menefee Formation by the proposed expansion of mining at the King II Mine are not likely. This also applies to the East Alkali Gulch crossing. Thus, impacts to groundwater quality in the Menefee Formation are expected to be negligible.

Point Lookout Sandstone Groundwater

The Point Lookout Formation contains one or more aquifers used by some domestic wells in watersheds adjacent to the CIAA (OSMRE 2017). Shale beds in the lower Menefee Formation act as confining layers above the Point Lookout, isolating aquifers in the Point Lookout Sandstone from the Menefee Formation. Because standard water well design in the region involves long screens that cross many formations, water reported as coming from the lower Menefee often is sourced in the Point Lookout Sandstone (OSMRE 2017; RHS 2016a). There are no discrete Point Lookout Sandstone groundwater users in the vicinity of the King II Mine. There is one abandoned windmill. For that reason, the Point Lookout Sandstone is not monitored by GCCE.

Point Lookout Sandstone Groundwater Quantity

Because of the hydraulic isolation of the Point Lookout Sandstone from the Menefee by the shales in the lower Menefee, there is no significant potential for mining to impact groundwater flow in the Point Lookout. This applies to the East Alkali Gulch crossing also. Thus, impacts to groundwater quantity in the Point Lookout Sandstone are expected to be negligible.

Point Lookout Sandstone Groundwater Quality

Because of the hydraulic isolation of the Point Lookout Sandstone from the Menefee by the shales in the lower Menefee, there is not a high potential for mining to impact groundwater quality in the Point Lookout. This applies to the East Alkali Gulch crossing also. Thus, impacts to groundwater quality in the Point Lookout Sandstone are expected to be negligible.

2.3.2.2 Cumulative Actions and Effects

Cumulative effects for surface water under the Proposed Action revolve around the Mormon Reservoir. The Mormon Reservoir receives water from irrigation return flows from irrigated areas outside of the Project Area as well as within the Project Area, and also receives groundwater inflow (OSMRE 2017). Water in the reservoir is subject to evaporation during the hot summer months. This leads to an increase in TDS and sulfate that limits the use of the water for irrigation of some crops (OSMRE 2017). The reservoir has not been sampled since 1975 but is scheduled for a four-quarter (one-year) sampling by GCCE to establish baseline for key parameters. The reservoir is privately owned, so access is controlled and requires permission from the owners before GCCE can begin sampling.

Cumulative effects for groundwater under the Proposed Action involve agricultural and domestic use of groundwater from the alluvial aquifer and the Point Lookout Sandstone aquifer. The Menefee and Cliff House formations are not good aquifers. Current mining by GCCE and the King II Mine and the proposed expansion of the King II Mine do not impact groundwater in any of the aquifers because groundwater is not pumped. Groundwater that seeps into the mine works from the Menefee Formation is either used by the mine or evaporated. Thus, it is unlikely that the Proposed Action or the East Alkali Gulch crossing would have a cumulative impact on groundwater because the mine does not pump groundwater as part of its current and proposed mining operations.

2.4 Cultural Resources

Cultural resources are defined as any definite location of past human activity identifiable through field survey, historical documentation, and/or oral evidence. Cultural resources include archaeological or architectural sites, structures, or places, and places of traditional cultural or religious importance to specified groups whether or not represented by physical remains. Cultural resources have many values and provide data regarding past technologies, settlement patterns, subsistence strategies, and many other aspects of history.

Cultural resources are protected and managed under a variety laws and regulations by federal agencies. The Dunn Ranch Area LBA and Mining Plan Modification Project is considered an undertaking subject to compliance with Section 106 of the National Historic Preservation Act (NHPA) of 1966. The NHPA (PL 89-665; 80 Stat. 915; 16 USC 470 et seq.), as amended, and its implementing regulations (36 CFR 60 and 800) require that federal agencies take into account the effects of their undertakings on important archaeological and historic sites in the area of potential effect (APE). In the terminology of NHPA, important sites are those that are determined to be eligible to the National Register of Historic Places (NRHP). Some sites require more information to determine eligibility; therefore, they are designated as unevaluated or need data sites. In the case of archaeological sites, this is usually provided through test excavation. Needs data sites are managed as though they are eligible for the NRHP until further evaluated. If these “need data” sites are to be affected by the undertaking, test excavation determines if salvage excavation is necessary or if no further work is needed.

Other primary laws under which cultural resource compliance studies are reviewed include the Archaeological Resources Protection Act (ARPA) of 1979 (PL 96-95; 93 Stat. 721; 16 USC 470aa et seq.) as amended (PL 100-555; PL 100-588); the American Indian Religious Freedom Act (AIRFA) of 1978 (PL 95-431; 92 Stat. 469; 42 USC 1996); and the Native American Graves Protection and Repatriation Act (NAGPRA) of 1990 (PL 101-601; 104 Stat. 3048; 25 USC 3001; 43 CFR Part 10). Cultural resources protected under ARPA, AIRFA, and NAGPRA are typically considered and evaluated under the review process set forth in Section 106 of the NHPA. In addition, the conservation of historic and cultural resources is established through federal policy as a component of the NEPA process (Section 101[b][4]) for federally authorized permits, funding, and projects (40 CFR Part 1 1502.16[g]). NEPA requires federal agencies to take into account cultural resources, including evaluation of potential impacts and mitigation measures, during the environmental analysis process. Regulations allow federal agencies to comply with Section 106 of NHPA through the use of the NEPA process and documentation, so long as the steps and standards of Section 800.8(c) of the Advisory Council on Historic Preservation’s (ACHP's) regulations are met.

Cultural properties considered significant and eligible for listing on the NRHP must possess integrity of location, design, setting, materials, workmanship, feeling, and association and must meet one or more of the following criteria:

- Criterion A: Association with events that have made a significant contribution to the broad patterns of our history
- Criterion B: Association with lives of persons significant in our past

- Criterion C: Embodiment of distinctive characteristics of a type, period, or method of construction, or representation of the work of a master, or possession of high artistic values, or representation of a significant distinguishable entity whose components may lack individual distinction

- Criterion D: Has yielded, or may be likely to yield, information important in prehistory or history

Most archaeological sites are evaluated in terms of Criterion D, although numerous exceptions occur, particularly if standing architecture or linear features are involved.

2.4.1 Affected Environment

The Project Area is located within the Northern San Juan cultural region, on the periphery of the Colorado Plateau physiographic province. Several cultural traditions are represented in the region, from Paleoindian occupation to the Euro-American settlement of the area, which includes both the existing King II lease and permit areas as well as the proposed lease modification area and the entire length of CR 120 in the Project Area. For an in-depth discussion of the culture history of southwestern LPC, the reader is referred to Winter et al. (1986) as well as Lipe et al. (1999).

As required by the NHPA, intensive archeological field investigations were conducted on the Project Area. **Table 2.4-1** is a summary of the past cultural resource inventory work completed in the Project Area.

Table 2.4-1 Previous Cultural Resource Inventories

Survey Year	Project Name	Affiliation	Acres Surveyed	NRHP-eligible Sites
2005	East Alkali Mine, Hay Gulch Area	CASA	50	None
2010	Class III Cultural Resource Inventory of the King II Mine Expansion	SWCA	160	5LP9601
2011	Archaeological Survey of Five Proposed 1-Acre Drill Hole Locations at the King II mine	PaleoWest	5	None
2013	A Class III Cultural Resource Inventory for Proposed Additional Drilling with the existing King II Coal Mine Lease Area A	PaleoWest	577	5LP10591.1*
2014	Class III Cultural Resource Inventory of 24 Test Drill Locations, 4 Revised Drill Locations, and Access Roads	PaleoWest	-	None
2014	Class III Cultural Resource Inventory of 9 Core Drill Sites	SWCA	-	None
2016	An Intensive Cultural Resource Inventory for GCCE Proposed Groundwater Monitoring Wells	SEAS	2.6	5LP11050
2018	Cultural Resource Survey of GCCE Phase II Coal Exploration Drilling (11 Exploratory Wells)	SEAS	5.7	None
2018	Cultural Resource Inventory for GCCE Proposed King II Mine Dunn Ranch LBA Project	SEAS	1,392	5LP11384** 5LP11386** 5LP11387**

*non-contributing segment to an NRHP-eligible resource within survey area

**Need data, sites are potentially eligible for the NRHP

In 2005, Complete Archaeological Service Associates (CASA) conducted a cultural and historic resources survey for the mine entrance surface disturbance areas. This survey covered ditch and irrigation upgrade work conducted under TR-25. No cultural resources eligible for listing on the NRHP were identified in this survey (CASA 2005).

In 2010, SWCA Environmental Consultants (SWCA) completed a Class III inventory for the appended 160-acre lease area. Two previously unrecorded sites and four isolates were identified during this inventory. Only one of the sites was recommended as eligible for listing on the NRHP: Site 5LP9601, a homestead dating to the late 19th to early 20th century. Isolates are not eligible for listing on the NRHP.

In 2011, PaleoWest Archaeology (PaleoWest) completed a Class III inventory of five proposed exploration drill hole locations. This survey identified two isolated finds that are not eligible for listing on the NRHP.

PaleoWest also completed a second pedestrian inventory of approximately 580 acres within the proposed lease expansion area in 2012. The cultural resource inventory was a mixture of reconnaissance and intensive level surveys (which loosely corresponds to Class II and Class III surveys, respectively). No cultural resources recorded during the survey were determined to be eligible for listing on the NRHP.

In 2013, PaleoWest conducted a Class III block inventory that included the locations of 11 proposed exploration drill sites. This inventory resulted in the discovery of seven historic archaeological sites and 50 isolated finds. The historic sites included road segments, a collapsed historic shack, a historic camp, an intake segment, and two dam and reservoir sites with associated intakes. The isolated finds included a variety of historic and prehistoric resources. PaleoWest recommended all sites as either not eligible to the NRHP or noncontributing segments of unevaluated resources. The State Historic Preservation Office (SHPO) recommended Site 5LP.10591.1 as a non-contributing segment of NRHP-eligible resource 5LP.10591 but determined that none of the other sites or isolated finds were eligible for listing on the NRHP.

In 2014, PaleoWest conducted intensive Class III inventories of 24 test drill hole locations, four revised drill hole locations, and 10 overland access corridors. During the inventories, PaleoWest recorded two new cultural sites and five isolated finds. One site is a prehistoric artifact scatter and the other appears to be a historic hunting shack. Four of the isolated finds are prehistoric and one is historic. All of sites and isolated finds were recommended as not eligible for the NRHP.

In 2014, SWCA performed a cultural resource survey of nine core drill sites. One isolated find that consisted of two fragments of aqua bottle glass were identified during the survey. No cultural or historic resources eligible for listing on the NRHP or significant archeological sites that may be affected by surface disturbance were identified.

In 2016, Stratified Environmental and Archaeological Services (SEAS) conducted a Class III cultural resource survey outside of the current lease permit boundary for four groundwater monitoring well drill sites. One newly recorded prehistoric site (5LP11050) was found. Site 5LP11050, a large Basketmaker III period encampment (ca. AD 600-750), is considered eligible for listing on the NRHP under Criterion D due

to its significant data potential. The proposed monitoring well site was relocated to avoid disturbing the cultural site.

The most recent inventory (SEAS 2018) inventoried the Dunn Ranch LBA area that included 1,392 acres. Three NRHP-eligible and four ineligible cultural resources were recorded. These three sites are all Late Archaic hunting and gathering camps.

2.4.1.1 Native American Concerns

The OSMRE and BLM initiated Government to Government consultations on October 30, 2018, by sending 60 consultation letters to 27 Native American tribes (**Table 2.4-2**) that have cultural affiliations to the APE. In accordance with the 2011 DOI Policy on Consultation with Indian Tribes and the NHPA of 1966, this included those from the Colorado Office of Archaeology and Historic Preservation directory of tribes with historic ties to Colorado.

Table 2.4-2 Native American Tribes Contacted

Nation	Response
Jicarilla Apache Nation	
Kewa Pueblo	
The Navajo Nation	
Ohkay Owingeh	
Pueblo de Cochiti	
Pueblo de San Ildefonso	
Pueblo of Acoma	
Pueblo of Isleta	
Pueblo of Jemez	
Pueblo of Laguna	
Pueblo of Nambe	
Pueblo of Picuris	
Pueblo of Pojoaque	
Pueblo of San Felipe	
Pueblo of Sandia	
Pueblo of Santa Ana	No concerns at this time
Pueblo of Santa Clara	
Pueblo of Taos	
Pueblo of Tesuque	
Pueblo of Zia	
Southern Ute Indian Tribe	Request consultation under Section 106 and copy of the Class III report
The Hopi Tribe	Requested copies of the survey report, draft EA, and any proposed treatment plans
Ute Indian Tribe (Uintah & Ouray Reservation)	

Nation	Response
Ute Mountain Ute Tribe	
Ysleta del Sur Pueblo	
Zuni Tribe of the Zuni Reservation	

No Native American religious concerns or potential traditional cultural properties within the permit area have been identified to date by the UMU Tribe, or by the Tribal Historic Preservation Officer (THPO), or by any of the other tribes consulted.

Additional Section 106 consultation letters were sent to the Southern Ute Indian Tribe and the Hopi Tribe on January 28, 2019 acknowledging their requests and providing Project background.

2.4.2 Environmental Effects

The Dunn Ranch Area LBA and Mining Plan Modification Project is considered a federal undertaking subject to compliance with Section 106 of the NHPA of 1966. The NHPA (PL 89-665; 80 Stat. 915; 16 USC 470 et seq.), as amended, and its implementing regulations (36 CFR 60 and 800) require that federal agencies take into account the effects of their undertakings on important archaeological and historic sites (i.e. historic properties) in the APE. In the terminology of NHPA, historic properties are those that are determined to be eligible to the NRHP. As such, OSMRE and BLM will assess whether the Project would have no effect, no adverse effect, or adverse effects to historic properties. Consultation with consulting parties including the SHPO Officer and Indian tribes including the UMU and other interested tribes is ongoing.

The APE for cultural resources includes the direct footprint above mining operations at the Dunn Ranch Area LBA and any areas of direct surface disturbance, as consulted on between the OSMRE and BLM with the UMU THPO and the SHPO. The APE covers a large area, primarily due to the possibility of surface subsidence resulting from underground mining operations. No surface modifications are proposed and no buffer zones were inventoried beyond the APE

Cultural resource sites can be directly or indirectly impacted by surface disturbing activities or the construction of associated mining infrastructure. Needs data sites are managed as though they are eligible for the NRHP until further evaluated. Indirect impacts may include increased subsidence, soil erosion and gullying, vibration from blasting, and dust from operations. In addition, there would be increased potential for unlawful artifact collection and/or vandalism of cultural resources.

Table 2.4-3 summarizes the cultural resources within the APE (i.e., permitted mine boundary and Dunn Ranch LBA). All of the sites are within the Dunn Ranch LBA.

Table 2.4-3 NRHP-Eligible Sites within the APE

Site Number	Site Type	Cultural Affiliation	NRHP Evaluation
5LP10572	Temporary Camp (hunting cabin)	Historic UMU	Not eligible
5LP11383	Temporary camp	Historic UMU	Not eligible
5LP11384	Artifact Scatter	Late Archaic	potentially eligible (needs data)
5LP11385	Artifact Scatter	Unknown historic	Not eligible
5LP11386	Artifact Scatter	Late Archaic	potentially eligible (needs data)
5LP11387	Artifact Scatter	Middle to Late Archaic	potentially eligible (needs data)
5LP11388	Ranching facility	Historic UMU	Not eligible

Archaeological sites are important for their potential to yield information providing a better understanding of prehistory; therefore, NRHP-eligible archaeological sites that cannot be avoided by the Project could be mitigated through conducting excavations intended to retrieve archaeological material and associated information. Reports would then be produced that summarize the excavations conducted at a site, interpret the activities performed on the site, and explain how investigation of the site has contributed to a better understanding of prehistory.

2.4.2.1 Direct and Indirect Effects

The potential surface disturbing activities would be less than 20 acres. Of the 7 cultural resource sites within the APE, none would be impacted by the Project as no surface disturbance is proposed in the site areas. Further, these sites would be subject to cultural resource avoidance monitoring requirements. If future mining operations cannot avoid NRHP-eligible sites, those activities would be federal undertakings subject to Section 106; a mitigation plan would be written, approved by OSMRE in consultation with SHPO, and implemented prior to planned mining activities. Any impacts to these sites would constitute an adverse, long-term effect. No mitigation or avoidance is required for sites that are not eligible for the NRHP.

Cultural resources (**Table 2.4-3**) could be impacted by subsidence as they are located above proposed panels. This potential impact is expected to occur very infrequently at the King II Mine due to a variety of factors, such as the stability of the Cliff House Sandstone (**Section 2.4.6**). As noted in **Section 2.4.6**, the subsidence that has occurred has been less than 1 foot in depth, and 0.25 to 0.5 ft in width. In the existing federal permit and lease areas, no effects to historic properties have been observed due to subsidence.

Potential impacts for all NRHP-eligible or potentially eligible sites could be monitored as part of the cultural resource monitoring requirements. Although very few workers would need to be in the area, to preclude the potential indirect impact of unlawful artifact collection and/or vandalism of cultural resources, mine personnel and sub-contractors would receive training on the identification of cultural sites and features, as well as the procedures to be followed and the legal penalties for failure to follow the guidelines, laws, and statutes.

If previously unidentified cultural sites are observed during actions within the permit area and could be affected by those actions, the appropriate cultural resource specialists, the UMU, and/or the SHPO, as appropriate, would be contacted for direction in protecting the resource.

For any proposed future ground-disturbing activities within the proposed lease and permit areas, GCCE is required by their OSMRE and CDRMS mine permits to complete cultural clearance surveys and obtain agency authorization prior to conducting any ground disturbances. Avoidance of cultural resources is the preferred approach to avoiding or minimizing potential impacts to the resource. As a result of regulatory oversight, avoidance measures, and when appropriate, data recovery, residual impacts to cultural resources would be negligible. Consultation with consulting parties is ongoing; however, the agencies anticipate a finding of no effect under the NHPA.

Native American Concerns

As discussed previously, cultural surveys have been conducted on UMU tribal lands within the Project Area to comply with Federal laws aimed at protecting cultural resources on Indian lands. On tribal lands, three sites, 5LP11384, 5LP11386, and 5LP11387, were identified that are potentially eligible to the NRHP and another four as ineligible (**Table 2.4-3**). None of these would be directly impacted by the Project as no surface disturbance is proposed in these areas and subsidence impacts are unlikely as discussed above. Further, these sites would be subject to cultural resource avoidance monitoring requirements. No traditional use areas have been identified to date within the permit area. At present, no Native American religious concerns or potential traditional cultural properties within the permit area have been identified by Indian tribes including the UMU Tribe. No effects to sites on tribally owned fee restricted lands are expected from the Proposed Action.

2.4.2.2 Cumulative Actions and Effects

The CIAA for cultural resources is the mine boundary and the Dunn Ranch LBA. Although direct impacts would be avoided, potential indirect impacts to cultural resources would come from the potential for subsidence. Ranching and livestock grazing impact cultural resources through trampling and artifact displacement. Additional coal leasing and subsequent development, as well as oil and gas leasing and development, would be subject to NHPA and Section 106 oversight.

Past and present ground disturbances in the CIAA that potentially affected cultural resources include coal mining activities and exploration, oil and gas development activities, ranching and livestock activities, dispersed residential development, road construction, and other developments**.** Sites that are not eligible for the NRHP do not have to be avoided and therefore, have likely been impacted by activities requiring the inventory. Changes to private agricultural lands near the CIAA are likely as some of these lands are converted in the future from traditional agricultural utilization (ranching) to more residential utilization. However, no specific plans are known, and these cannot be evaluated for this cumulative impacts analysis.

Past, present, and reasonably foreseeable disturbance to cultural resources in the CIAA have been and would be the result of mining activities, utility infrastructure, road development, archaeological excavation, livestock grazing, private development, and likely vandalism and artifact collection. Private development and vandalism/artifact collection are not quantifiable.

Section 106 of the NHPA requires consideration of the effects of federal actions to historic properties. If historic properties (i.e., NRHP-eligible cultural resources) cannot be avoided by the Proposed Action, these sites would be subject to a resolution of adverse effects, which may include mitigation such as data recovery. Consultation with consulting parties is ongoing; however, OSMRE and BLM anticipate a finding of no effect under the NHPA. Any future actions requiring federal approval that could adversely affect historic properties would be defined as future undertakings and are not expected. If historic properties are not avoided, the Project would contribute to cumulative impacts to historic properties in combination with past, present, and reasonably foreseeable future activities in the CIAA.

3.0 REFERENCES AND ACRONYMS

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3.2 Acronyms and Abbreviations

Acronym/Abbreviation	Definition
AIRFA	American Indian Religious Freedom Act
APCD	Air Pollution Control District
APE	Area of Potential Effect
AQRV	Air Quality Related Values
ARPA	Archaeological Resources Protection Act
bgs	below ground surface
BLM	Bureau of Land Management
CAA	Clean Air Act
CAMx	base model platform configuration
CARMMS	Colorado Air Resources Management Modeling study
CASA	Complete Archaeological Service Associates
CDPHE	Colorado Department of Public Health and Environment
CDRMS	Colorado Division of Reclamation, Mining, and Safety
cfs	cubic ft per second
CH_4	methane
CIAA	cumulative impact analysis area
CMM	coal mine methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
dv	deciviews
EA	Environmental Assessment
EO	Executive Order
EPA	Environmental Protection Agency
FLIGHT	Facility Level GHG Tool
ft	foot or feet
ftasml	feet above mean sea level
ftbgs	feet below ground surface
GCCE	GCC Energy, LLC
GHGs	greenhouse gases
gpm	gallons per minute
GWPs	global warming potentials
ha	hectares
HAP	hazardous air pollutant
Hg	mercury
hp	horse power
Hz	Hertz
IPCC	Intergovernmental Panel on Climate Change
IWG	Interagency Working Group
kgN	kilograms of nitrogen

Acronym/Abbreviation	Definition
km	kilometer
LBA	Lease by Application
lbs	pounds
LCC	low cover crossing
LPC	La Plata County
mg/L	milligram per liter
MMt	million metric tons of carbon dioxide equivalents
MSHA	Mine Safety and Health Administration
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAGPRA	Native American Graves Protection and Repatriation Act
NEI	National Emissions Inventory
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NHPA	National Historic Preservation Act
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRHP	National Register of Historic Places
NSPS	New Source Performance Standards
O_3	ozone
OSMRE	Office of Surface Mining Reclamation and Enforcement
PaleoWest	PaleoWest Archaeology
PM_{10}	particulate matter 10 microns
$PM_{2.5}$	particulate matter 2.5 microns
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
RCPs	Representative Concentration Pathways
RHS	Resource Hydrogeologic Services
SCC	Social Cost of Carbon
scf	standard cubic foot
SEAS	Stratified Environmental and Archaeological Services
SHPO	State Historic Preservation Office
su	standard units
SWCA	SWCA Environmental Consultants
TDF	tire derived fuel
TDS	total dissolved solids
THPO	Tribal Historic Preservation Office
tpy	tons per year
TRFO	Tres Rios Field Office
TRR	Technical Resources Report

Acronym/Abbreviation	Definition
UMU	Ute Mountain Ute
VAM	average ascent speed
VOC	volatile organic compound
WRF	Weather Research and Forecasting
yr	year
$\mu g/m^3$	micrograms per cubic meter of air